Issues in Focus

Electricity: Renewable Portfolio Standards

In an increasingly competitive U.S. electricity market, regulators and legislators at both the State and Federal levels are looking for ways to stimulate the development of generating capacity that uses renewable energy sources. One approach that has received considerable attention is the imposition of a renewable portfolio standard (RPS), which would promote the use of renewables by establishing a minimum annual share of electricity generation (or sales) that must come from specified types of renewable facilities. Owners or operators of qualifying renewable facilities would receive credits for each kilowatthour they generated, and the credits could be used in the current year, held for future use (banked) or sold to others to ensure that their mix of power (portfolio) contained a specified share of renewable generation.

The main differences among the various RPS proposals are the required renewable share, the timing of the program, the definition of qualifying facilities, and whether or not there is a limit (cap) on the allowable price for renewable credits. For example, the Administration's proposed Comprehensive Electricity Competition Act (CECA), submitted to Congress on April 15, 1999, includes a Federal RPS that would apply to all U.S. electricity suppliers. The key provisions of the CECA RPS are:

- The required renewable share of electricity sales would be set at 2.4 percent [*22*] for the years 2000 to 2004, increase to 7.5 percent by 2010, and then remain at 7.5 percent through 2015, after which it would expire (sunset).
- Qualifying renewables would include geothermal, biomass (including biomass used in coal-fired plants), solar thermal, solar photovoltaic, wind, and the portion of municipal solid waste (MSW) that consists of biomass products [*23*].
- The price for renewable credits would be capped at 1.5 cents per kilowatthour. If the market price for the credits rose above the cap, electricity retailers would be able to purchase credits from the U.S. Department of Energy (DOE) at the 1.5-cent price (with the resulting revenues deposited in a Public Benefits Fund). In that event, the qualifying renewable share actually achieved would fall below the required 7.5-percent share.

Other provisions of the CECA RPS include double credit for qualifying renewable generation on Indian lands or generation anywhere from biomass resources coming from Indian lands. In addition, qualifying renewable facilities taking advantage of other renewable incentive provisions of CECA could not receive credits under the RPS program.

To examine the potential impacts of the proposed RPS in CECA—independent of its other provisions—three sensitivity cases were prepared, analyzing the key features of the RPS:

- The *RPS with cap and sunset case* incorporates both the price cap for renewable generation credits (1.5 cents per kilowatthour) and the sunset provision (expiration after 2015).
- The *RPS with cap, no sunset case* includes the price cap but not the sunset provision, continuing the RPS throughout the projection period to 2020.
- The *RPS no cap, no sunset case* does not include either the price cap (the price of credits is allowed to rise to its full market value) or the sunset provision.

None of the sensitivity cases includes the Indian lands provisions of CECA. At this time, information on the quantity and quality of renewable resources available on Indian lands is insufficient for model analysis. A comparison of maps of available wind and biomass resources and maps of Indian lands shows some overlap, but more information would be needed for an assessment of the potential impact of the CECA provisions.

The RPS requirement does stimulate additional renewable generation and capacity in each of the three cases; however, the analysis suggests that the price cap and sunset provisions could prevent the 7.5-percent target share from being achieved. The combined effect of the 1.5-cent credit cap and the 2015 sunset is to reduce the average economic value of the proposed RPS credit. Under the proposal, receipt of the few early years' incentive—at a maximum of 1.5 cents per kilowatthour and only through 2015—would need to compensate for the higher costs of renewable energy facilities over their full productive life. In effect, then, the average additional cost of producing electricity from a renewable energy facility would have to be well below 1.5 cents per kilowatthour if significant additional amounts of new renewable capacity were to be built as a result of the CECA RPS.

In the *AEO2000* reference case, with no RPS, 6.6 gigawatts of new qualifying renewable generating capacity are installed by 2010, and an additional 3.6 gigawatts are added between 2010 and 2020. In total, qualifying renewables provide approximately 3.0 percent of U.S. electricity sales in both 2010 and 2020 in the reference case. In the RPS with cap and sunset case, generation from qualifying renewables reaches 3.9 percent of electricity sales in 2010, then declines to 3.4 percent in 2020. In 2010, just under 50 percent of the required RPS share is met through purchases of credits from the Federal Government.

Nearly 82 percent of the 36-billion-kilowatthour difference in qualifying renewable generation between the reference case and the RPS with cap and sunset case in 2010 comes from increased use of biomass for co-firing in existing coal plants (Figure 8), and only 800 megawatts of additional qualifying renewable capacity is added in this RPS case.

Removing the 2015 sunset provision encourages additional increases in renewable generation and capacity, especially in the later years of the projections. The qualifying renewable share in 2010 is 3.9 percent in the RPS with cap, no sunset case—the same as in the RPS case with cap and sunset—but it increases to 4.2 percent in 2020. In the first case, the incentive to use biomass in coal plants disappears when the RPS expires; but without the sunset provision, continued co-firing of biomass in coal plants along with higher geothermal generation increases the qualifying renewable share to 4.2 percent.

In the RPS no cap, no sunset case a large amount of qualifying renewable capacity is added to meet the 7.5-percent CECA RPS target. Relative to the reference case, more than 30 gigawatts of additional wind capacity, 9 gigawatts of additional biomass capacity, and more than 5 gigawatts of additional geothermal capacity are added by 2020 (Figure 9). Total U.S. wind capacity reaches nearly 36 gigawatts in 2020 in the third RPS case, approximately 18 times the amount that existed in 1998. Even in this case, however, solar technologies remain too costly for additional penetration into central station generation markets. Similarly, no additional MSW generating plants are projected, because of their high capital costs and environmental concerns. It is possible, however, that output from existing MSW-powered facilities could increase somewhat in response to the RPS credit price incentive.

The impact on electricity prices is relatively small in each of the three RPS cases (Figure 10). Although new renewable facilities are more expensive to build and operate than new gas-fired facilities, the RPS credit system would spread the incremental costs of new renewable facilities across all electricity sales. The largest change in electricity prices is projected for the RPS no cap, no sunset case in 2010, at 3.2 percent above reference case prices. Even in this case, however, electricity prices in 2020 are only 1.4 percent above the reference case prices. The changes in electricity prices do change the Nation's total annual electricity bill. In 2010, the projected increase in total expenditures for electricity purchases relative to the reference case projection ranges from $500 million in the RPS with cap and sunset case to $5.8 billion in the RPS no cap, no sunset case (in 1998

Figure 8. Renewable electricity generation in four cases, 2010 (billion kilowatthours)

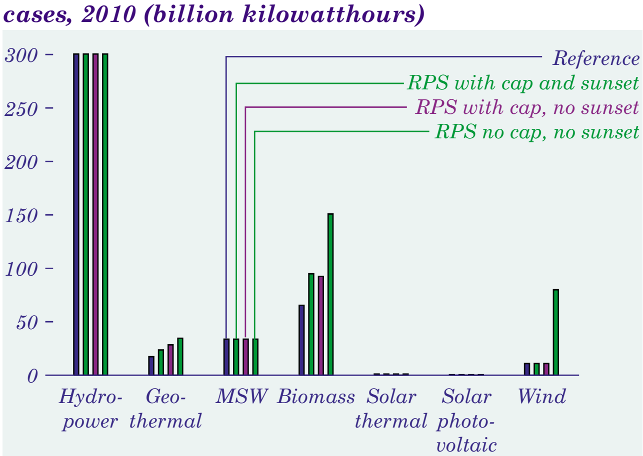


Figure 9. Renewable electricity generation in four cases, 2020 (billion kilowatthours)

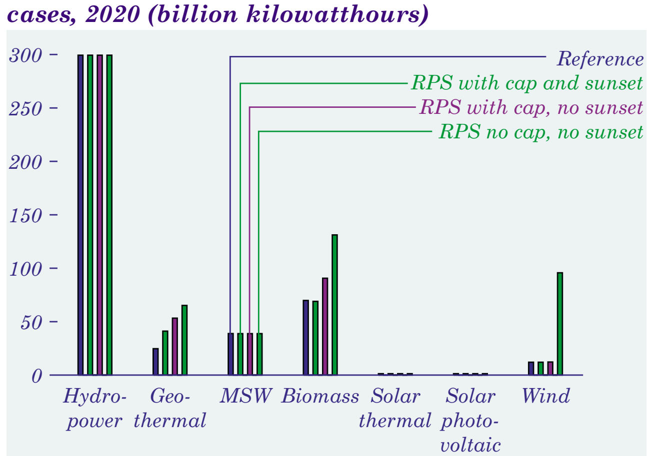
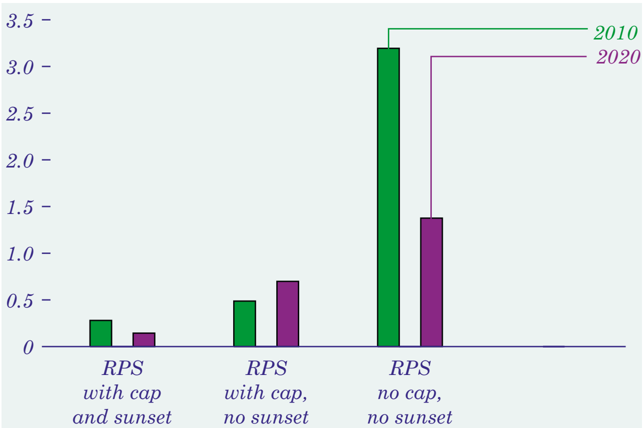


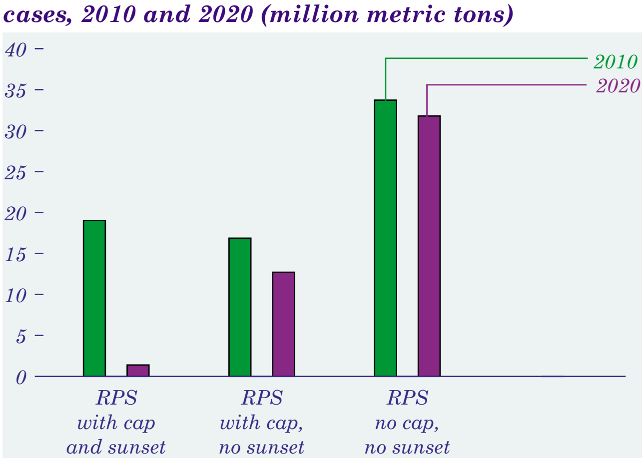
Figure 10. Difference from reference case electricity prices in three cases, 2010 and 2020 (percent)



dollars). In 2020 the differences range from $200 million to $2.1 billion.

As with electricity prices, the three RPS cases have relatively small impacts on U.S. carbon emissions (Figure 11). In the RPS with cap and sunset case, carbon emissions are estimated to be 19 million metric tons below the reference case level in 2010 and 1 million metric tons below the reference case level in 2020. The reduction is smaller in 2020, because the RPS expires in 2015. In the second RPS case (with the credit price cap but no sunset), carbon emissions are expected to be 13 million metric tons (0.6 percent) below the reference level in 2020. The impact is largest when both the price cap and sunset provisions are removed, because renewable generation is much higher. In this case, carbon emissions are 34 million metric tons (1.9 percent) and 32 million metric tons (1.6 percent) below reference case levels in 2010 and 2020, respectively.

Figure 11. Carbon emissions reductions in three cases, 2010 and 2020 (million metric tons)



The key result of this analysis is that, except in the RPS case with no price cap and no sunset provision, the share of electricity sales generated from qualifying renewables is likely to fall short of the 7.5-percent CECA target. In the first RPS case, the amount of generation from qualifying renewables increases by only a small amount above the reference case level. The economic value of the limited (capped at 1.5 cents per kilowatthour), temporary (through 2015) renewable energy credit is not large enough to overcome the cost advantage of fossil fuel technologies, especially new natural-gas-fired turbine and combined-cycle plants. The costs of new renewable plants are expected to continue to decline, but the cost and performance of fossil technologies also are projected to improve. As a result, the combination of the 1.5-cent renewable credit price cap and the need to recover any above-market costs of new qualifying renewable plants before the RPS expires in 2015 appears likely to limit the impact of the proposed CECA RPS on the development of new renewable electricity generating capacity.

Although it is not included in this analysis, if the 1.5 cent per kilowatthour production tax credit for generation from new wind and biomass facilities, which expired in June 1999, were extended, the amount of qualifying renewable generation stimulated by the RPS would be larger than projected in the RPS with cap and sunset case. Efforts to extend the credit through 2004 have been proposed, but they have not been approved. If the tax incentive were extended through 2020, the projected generation from wind units in 2010 would be 32 percent higher than projected in the RPS with cap and sunset case. In 2020, generation from biomass would be 10 percent higher, and generation from wind would be 46 percent higher. Continuation of the incentive would encourage the development of an estimated 1.41 gigawatts of additional biomass capacity and 1.81 gigawatts of additional wind capacity relative to the RPS with cap and sunset case, and carbon emissions in 2020 would be 2 million metric tons lower.

Electricity: Competitive Pricing

As States restructure their electricity markets, increasing numbers of consumers have the opportunity to choose their electricity suppliers. While this by itself represents a significant market adjustment, there may be an even more profound change in the way electricity is priced. In the past, electricity prices have had three components: generation, transmission, and distribution. The following analysis assumes that the generation component will be unbundled from transmission and distribution services, which will continue to be regulated.

Until recently, electricity prices in the United States were regulated on the basis of the average cost of producing and delivering electricity to consumers (cost of service). State regulators determined the average "embedded cost" of electricity generation by adding all costs—including fuel, recovery of investment costs, operations and maintenance costs, and a regulated profit—and dividing by the number of kilowatthours sold. Since about 1995, however, there has been a gradual movement by individual States toward competition in electricity generation services. Under competition, prices for generation are expected to approach the marginal, rather than the average, cost of production.

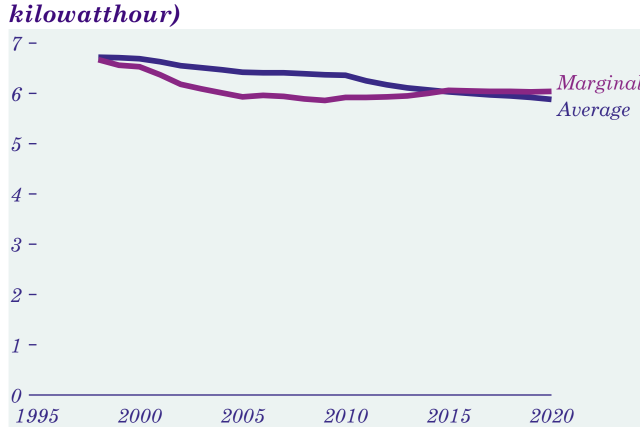
The movement to prices based on marginal costs has several implications. First, electricity prices are likely to vary from hour to hour as consumer demand changes. In most of the country, consumer demand for electricity during a typical summer day is lowest in the early morning hours, when people are asleep and businesses are closed. Through the day, demand rises as temperatures rise and homes and businesses use more air conditioning. As a result, in the early morning hours, only generators with the lowest operating costs are running. Over the course of the day, more expensive generators are brought into service. Because the costs of generating power are based on the last unit brought on line during any given time period (the "marginal unit"), market prices typically rise as demand increases. In a truly competitive market, demand and supply are kept in balance during periods of extremely high demand through an increase in the price corresponding to the cost of electricity supplied by the marginal generating unit.

This analysis discusses the impacts of a movement to electricity prices based on marginal costs and their sensitivity to demand variations and the operating costs of the marginal generator. Because the marginal generator typically consumes natural gas, three sensitivity cases are discussed: low gas price, mid gas price, and high gas price. The cases incorporate the common assumption of competitive electricity prices but differ in the assumed wellhead price of natural gas. In each of the three cases it is assumed that competition will be phased in over a 10-year period, reflecting the transition to a competitive market and recovery of stranded costs. Full competition, with generation prices based entirely on marginal costs, is assumed to begin in 2008.

Initially, at the national level, marginal operating costs would be lower than average embedded costs (Figure 12). Because some plants have costs, including recovery of construction costs, that make them uneconomical in today's market for power, competitive electricity prices (based purely on marginal operating costs) fall below the average-cost-based (regulated) prices until near the end of the projection period. The gap is fairly narrow, because it is assumed that the transition to competitive prices based on marginal costs will occur slowly over a 10-year period, and that improvements in operating costs that have already occurred in recent years will continue with or without a movement to full retail competition. It is unclear whether full retail competition will spur additional improvements beyond those that are already occurring. After 2015, rising gas prices cause marginal prices to slightly exceed average-cost-based prices. If retail competition leads to additional operating cost improvements, marginal costs might remain below average costs after 2015.

The difference between the two price lines in Figure 12 represents a rough measure of stranded costs. In a few regions of the country, where average costs already are extremely low, stranded costs may be negligible or actually negative. In most regions, marginal-cost-based prices in 2010 are expected to be up to 16 percent lower than average-cost-based prices. Only in the Northwest, where average-cost-based prices are very low as a result of the large share of low-cost hydroelectricity, would marginal-cost-based

Figure 12. Marginal- and average-cost-based prices for electricity in the competitive pricing case with reference gas prices, 1998-2020 (1998 cents per kilowatthour)



prices be higher, by about 10 percent. It is also possible that, in a competitive pricing environment, some costs could rise—such as the costs of sales, marketing, and system operations. The recovery of such costs in competitive prices might reduce the amount of stranded costs. Over time, the difference between costs and prices narrows, as stranded costs are recovered or written off.

Over the course of a year, competitive prices vary with demand. In the fall and spring, when consumer needs for electricity are relatively low, prices are also low. Conversely, in the summer, or when a large number of plants are out of service, prices rise as the most expensive generators—normally idle—are brought on line to meet demand. In the sample region and season shown in Figure 13, the generation component of competitive prices in 2020 ranges from a high of 17 cents per kilowatthour to a low of just over 2 cents per kilowatthour in the mid gas price case. Because the periods of high prices are expected to be limited to only a few hours during the season, they have a relatively small impact on the average annual price.

In all the marginal cost cases, it is assumed that consumers will see and respond to the effect of time-of-use prices. This response has the effect of reducing the total capacity needed over the course of the projection in comparison with the reference case, primarily through a reduction in the need for combustion turbines used to meet peaking loads.

Figure 14 shows the technology type of the marginal unit for the years 2000, 2010, and 2020 by region in the mid price case. In most regions, the marginal generating unit throughout most of the year uses natural gas. As a result, natural gas prices will have a far greater effect on electricity prices under marginal cost pricing than under average cost pricing.

The high and low gas price cases—which incorporate alternative assumptions about improvements in natural gas recovery and distribution technology, leading to different gas price paths—are used here for illustrative purposes, to demonstrate how competitive electricity prices might respond. As in the mid price case, it is assumed in the low and high price cases that competition will be phased in over a 10-year period, with full competition and prices based entirely on marginal costs by 2008. The mid price case assumes moderate improvement in natural gas availability, the low gas price case assumes rapid improvement, and the high gas case assumes little improvement.

Table 2 shows projected wellhead natural gas prices in the three cases. Higher or lower gas prices affect both the average embedded cost and the marginal cost of electricity generation; however, the effects differ in magnitude (Figure 15 and Tables 3 and 4). With 20 percent lower gas prices in 2020 in the low price case, average-cost-based prices are only 3 percent lower than in the mid price case, but marginal-cost-based prices are 8 percent lower. Similarly, with 32 percent higher gas prices in 2020 in the high price case, average-cost-based prices are

Figure 13. Generation price by hour for a sample region and season (1998 mills per kilowatthour)

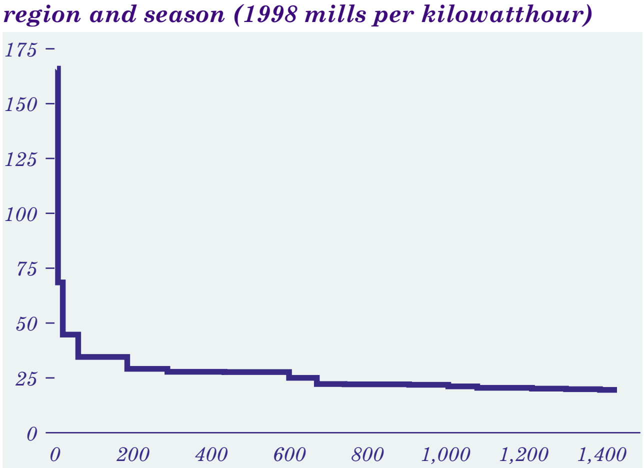


Figure 14. Projected percentage of time marginal electricity prices are set by different capacity types, 2000, 2010, and 2020 (percent of total year)

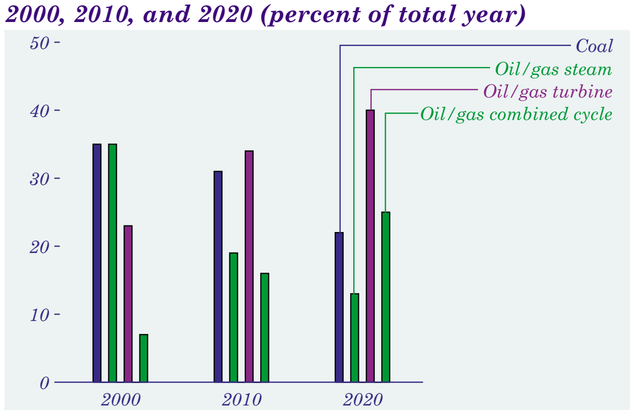


Table 2. Natural gas wellhead prices in three cases, 2000-2020 (1998 dollars per thousand cubic feet)

	2000	2010	2015	2020
Low gas price	2.16	2.34	2.24	2.26
Mid gas price	2.17	2.59	2.70	2.82
High gas price	2.17	2.88	3.20	3.71

(See note for Table 2 on page 107)

Figure 15. Marginal- and average-cost-based prices for electricity in three competitive pricing cases, 1998-2020 (1998 cents per kilowatthour)

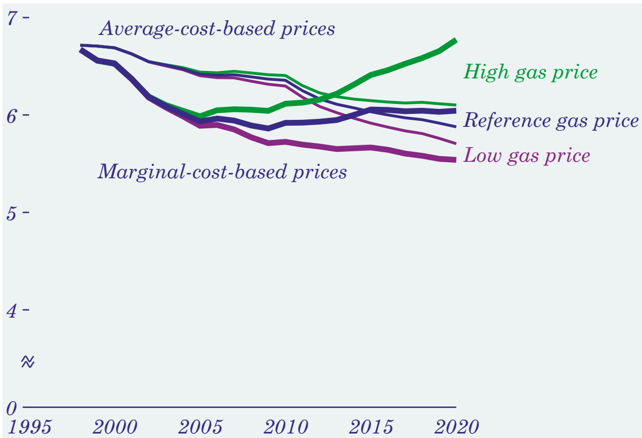


Table 3. Regulated (average-cost-based) electricity prices in three cases, 2000-2020 (1998 cents per kilowatthour)

	2000	2010	2015	2020
Low gas price	6.7	6.3	5.9	5.7
Mid gas price	6.7	6.4	6.0	5.9
High gas price	6.7	6.4	6.2	6.1

Table 4. Competitive (marginal-cost-based) electricity prices in three cases, 2000-2020 (1998 cents per kilowatthour)

	2000	2010	2015	2020
Low gas price	6.5	5.7	5.7	5.5
Mid gas price	6.5	5.9	6.1	6.0
High gas price	6.5	6.1	6.4	6.8

3 percent higher than in the mid price case, but marginal-cost-based prices are 13 percent higher. In the high gas price case, marginal-cost-based prices actually exceed average-cost-based prices by 11 percent in 2020. The difference is explained by the fact that prices based on marginal costs are much more sensitive to changes in the operating cost of the marginal unit than are prices based on average costs.

Natural Gas: Industry Expansion

Pipeline Capacity

Considerable expansion of the interstate pipelines that transport natural gas will be needed between now and 2020 to satisfy the demand for natural gas that is projected in the *AEO2000* reference case. Although the overall increase in pipeline capacity would be significant, the industry demonstrated the ability to handle expansions of the same order of magnitude in the early 1990s. The increase in demand for natural gas in the reference case would require pipeline capacity increases of approximately 2 percent a year from 1999 through 2001 for capacity crossing the 12 regions represented in the projections. By comparison, from 1991 through 1993, capacity grew by an average of more than 4 percent a year (Figure 16). The total increase from 1991 through 1993 was 3.2 trillion cubic feet, compared with the 2.7 trillion cubic feet of new capacity needed from 1999 through 2001.

Much of the expansion expected through 2001 is already underway, and several major projects are likely to be completed in 1999 or 2000. The current projects are providing access to new sources of both supply and demand, as well as increasing capacity along transportation corridors where utilization is high during peak periods and bottlenecks either are already occurring or could occur in the near future.

After 2001, the projected annual growth of pipeline capacity slows to less than 1 percent a year. One reason is that most of the projected increase in demand for natural gas is for electricity generation, much of which can be met by increasing and levelizing the load on existing capacity without additional expansion of the pipeline infrastructure (Figure 17). Thus, although actual capacity expansion slows after 2001, flows on the interstate pipeline system increase significantly (Figure 18). Total interregional gas flow across the 12 domestic regions and Canada is projected to grow from 25.7 trillion cubic feet a year in 2001 to 35.2 trillion in 2020, an increase of 36.8 percent, compared with a capacity increase of 14.5 percent.

In 1998, 18.7 percent of total U.S. natural gas consumption was for space heating in the residential and commercial sectors, and 17.2 percent was for electricity generation. As a result, both demand and pipeline capacity utilization peaked during the

Figure 16. Additions of interregional natural gas pipeline capacity, 1991-2020 (billion cubic feet)

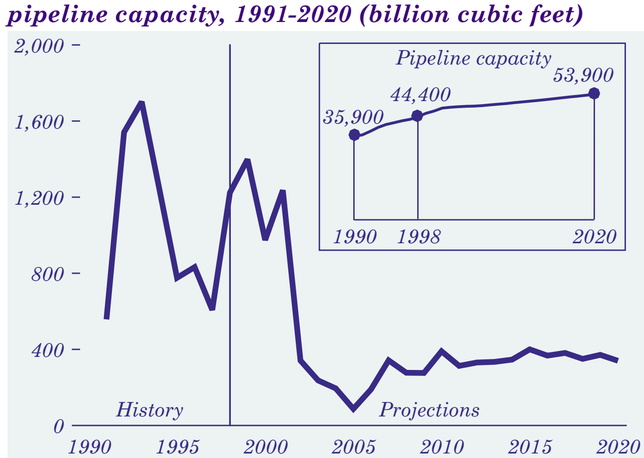
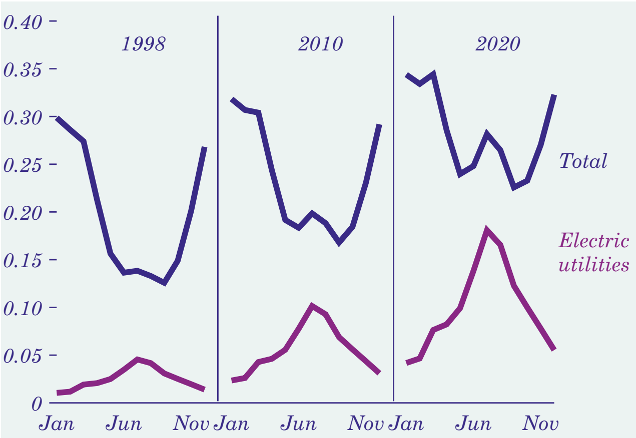


Figure 17. Total natural gas use and use for electricity generation by month in the Mid-Atlantic Census division, 1998-2020 (quadrillion Btu)



winter heating season, whereas significant amounts of capacity were idle during the summer months. In the *AEO2000* forecast, more than half the total projected increase in natural gas consumption is for electricity generation. In 2020, gas use for space heating makes up only 16.2 percent of the total and use for electricity generation grows to 29.4 percent, significantly increasing the utilization rate of existing capacity during the summer. Some new capacity will be needed to provide service to residential, commercial, and industrial users (as well as to new gas-fired generating plants in areas not currently or adequately served), but much of the increased load will be handled by excess space on pipelines during traditionally off-peak periods.

One of the forces behind capacity expansion has been, and will continue to be, the desire to provide access to new and expanding production areas. Significant increases in annual production are projected for the Rocky Mountain and Gulf Coast onshore production regions between 1998 and 2020—2.31 and 1.71 trillion cubic feet, respectively (Figure 19). For the Rocky Mountain region, an area that has long experienced bottlenecks in pipeline capacity that have prevented full use of its production capacity, the additional production represents a 79.7-percent increase from 1998 levels.

Several pipeline projects recently completed will provide producers in the Rocky Mountain region with new access to customers in the Midwest. KN

Figure 18. Natural gas pipeline flows between Census divisions, 1990-2020 (trillion cubic feet)

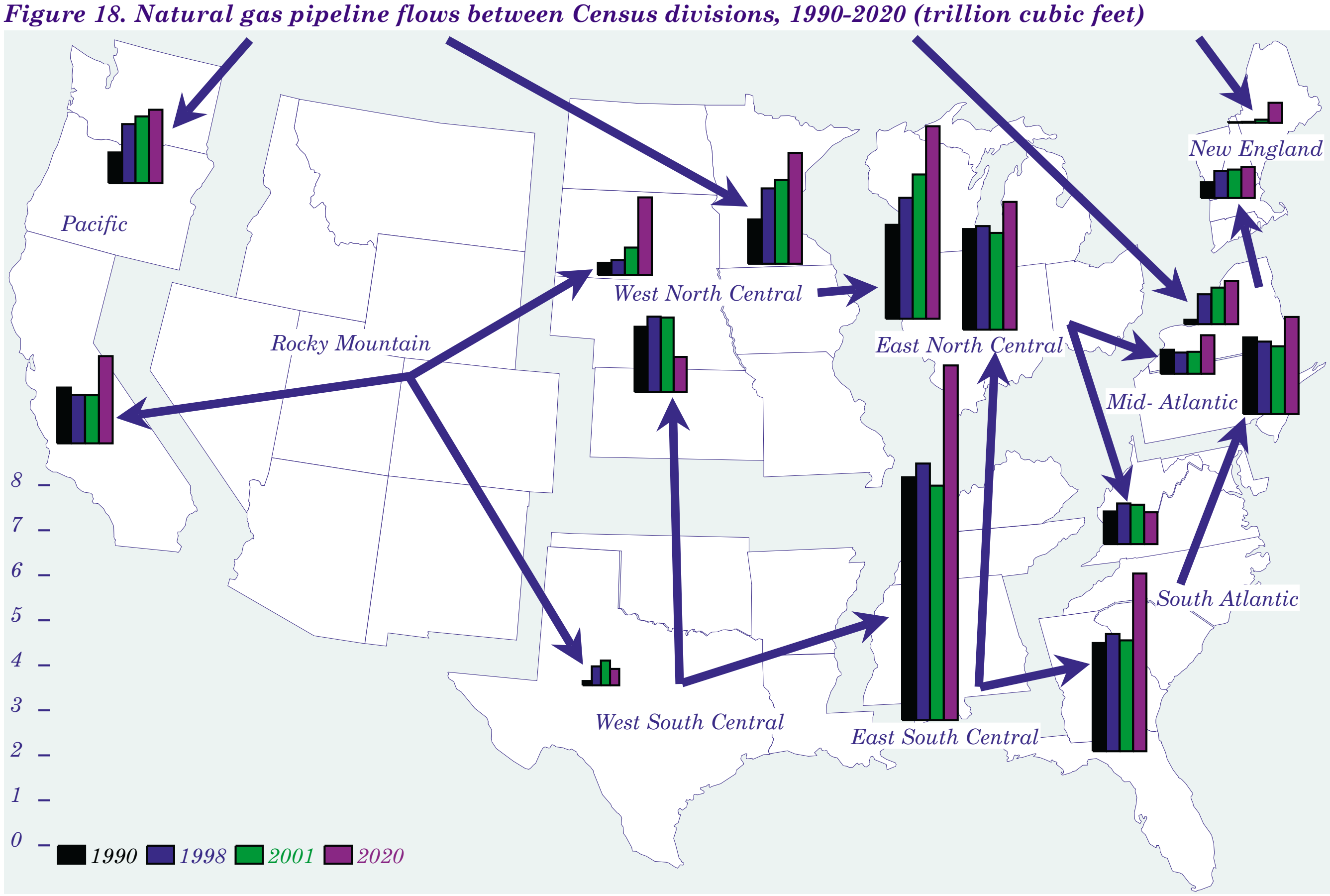
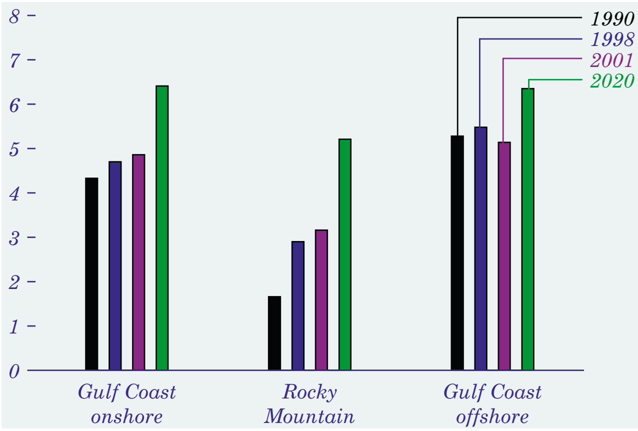


Figure 19. Natural gas production in three regions, 1990-2020 (trillion cubic feet)



Interstate's new Pony Express project and the Trailblazer system expansion provide access from the Wyoming and Montana production regions, and the Transwestern Pipeline and El Paso Natural Gas expansions have increased the capacity to move supplies out of New Mexico's San Juan Basin. Along with increases in capacity, significant increases in flows from the region to markets on the east and west coasts are expected between 1998 and 2020.

Canada is another rapidly expanding source of natural gas supply for U.S. consumers. The greatest increase in pipeline capacity from 1990 to the present has been a near doubling of import capacity between western Canada and the United States. As a result, markets in the United States have been able to tap into western Canadian supplies, mainly from Alberta and British Columbia. The most significant recent pipeline project is the Northern Border expansion through Montana into the Midwest. In addition, several major projects are expected to be completed within the next few years. The Alliance pipeline system, scheduled to be completed in 2000, will move supplies from western Canada to markets in the Midwest and Mid-Atlantic regions, and the Maritime & Northeast system, also scheduled for completion in 2000, will transport Sable Island supplies to markets in New England. Additional expansions have been proposed, including the NOVA system expansion that would link with the TRANSCANADA expansion to move additional supplies to U.S. markets.

The expansion of gas pipeline capacity between the United States and Canada is projected to continue throughout the forecast period at an average rate close to 1.8 percent a year. As production in western Canada continues to increase, gas flows into the West North Central region are expected to increase by 47.2 percent and flows into the Pacific region by 24.3 percent between 1998 and 2020. Eastern Canada will become a new source of U.S. supply as resources from Sable Island off the eastern coast of Nova Scotia are developed. Imports into New England, largely from Sable Island, are expected to reach 448 billion cubic feet a year by 2020.

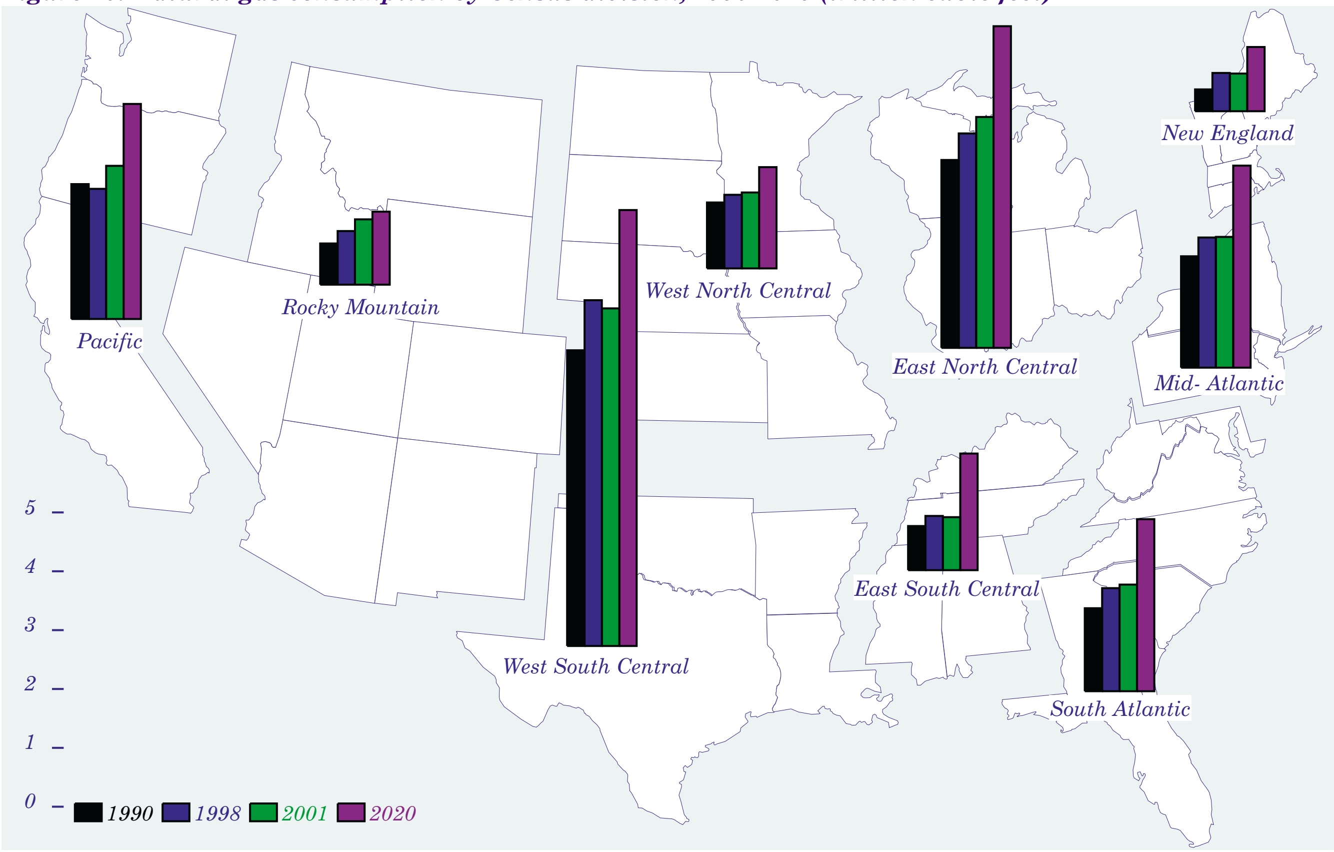
The third area of expanding production is the Gulf Coast offshore region. There has been considerable pipeline expansion in the area, but much of it is for gathering systems and short-haul pipelines to move supplies onshore, rather than major interstate pipeline expansions. Expansion out of the East South Central and West South Central regions was strong from 1990 through 1998 but has slowed recently along with a slowdown in production. Offshore Gulf Coast production continues to grow steadily in the projections, picking up after 2001 as a result of further deepwater exploration and development.

Between 1998 and 2001, the reference case shows little expansion of interstate pipeline capacity from the Gulf Coast region. Increases are expected between 2001 and 2020, as Gulf Coast producers expand production and seek access to eastern markets. Although potential shortages of skilled manpower and offshore drilling rigs lend some uncertainty to the prospect for increased offshore production in the short term, investments continue to be made in exploration and production, and it is anticipated that the rising levels of both demand and prices for natural gas throughout the forecast will provide the necessary economic incentives.

Also important as a motivation for pipeline capacity expansion are shifting and growing demand areas (Figure 20). New England saw the strongest percentage increase in demand (75.7 percent) from 1990 to 1998, and continued increases are projected through 2020, at an average of 2.4 percent a year. In the absence of the pipeline infrastructure to bring gas into the area, oil long dominated New England markets. In 1998, New England was the only region in which oil use was higher than natural gas use in the residential sector. With natural gas infrastructure expansion in the 1990s, however, the picture is now changing.

Capacity entering New England increased by more than 50 percent from 1990 through 1998, facilitating

Figure 20. Natural gas consumption by Census division, 1990-2020 (trillion cubic feet)



strong growth in overall natural gas consumption. Still, New England lags behind the rest of the Nation in natural gas use and thus presents an opportunity for the natural gas industry. More natural gas use in all sectors is projected, and gas-fired electricity generation is expected to grow more than fivefold. Increases in pipeline capacity to serve the area, especially to provide access to Canadian supplies, are expected to continue, nearly doubling current gas flows into New England by 2020.

The largest absolute increases in capacity between 1998 and 2020 are expected for the corridors serving the West North Central, South Atlantic, and Pacific regions, where demand for natural gas is projected to grow by 1.5, 2.4, and 2.3 percent a year, respectively, between 1998 and 2020. In the South Atlantic region, rapid population growth is expected to increase the demand for natural gas in all sectors, and especially for electricity generation. Gas-fired electricity generation is projected to more than double in the South Atlantic region between 1998 and 2020. Gulf Coast supplies destined for the Northeast will also flow through the South Atlantic, increasing even more the need for added capacity. Similarly, Canadian and Mountain Region supplies will flow through the West North Central Region en route to the Northeast.

Although the growth in demand for natural gas has slowed in the Pacific region in recent years, partly as a result of increases in hydroelectric generation, it has recently begun to accelerate. Consistent growth is projected for the Pacific region in the reference case through 2020. Two proposed projects, Questar's Four Corners project and the Kern River expansion, would move an estimated 430 million cubic feet per day into California.

All this expansion requires considerable investment. In 1997 and 1998, it is estimated that more than $2 billion was invested in pipeline expansion. The projected costs for new capacity on completed and proposed natural gas pipeline projects from 1996 through 2000 average 15 cents per cubic foot per day for projects consisting predominantly of compression, 26 cents for pipeline system expansions of 250 miles and over, and 94 cents for new projects 250 miles and over.

Although all are not likely to be built, more than 100 pipeline projects have already been proposed for 1998 through 2001. For the 70 projects for which preliminary estimates are available, the estimated costs total more than $12.3 billion. The largest is the Alliance project, which has been estimated to cost as much as $1.81 per added cubic foot per day of capacity, for a total project cost of more than $2.9 billion [*24*]. Because the costs of expansion vary widely depending on many factors, including the type of expansion (compression, looping, or new pipe), the size of the expansion, and the area of the country, averages based on recent project costs are used in estimating the costs associated with projected expansions.

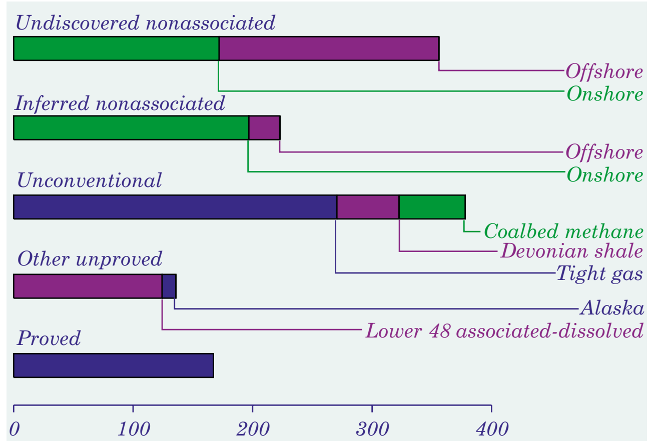
The pipeline capacity expansion currently underway and proposed reflects the industry's anticipation of an expanding market. The rising levels of consumption and prices for natural gas projected in *AEO2000* will provide the economic incentives for the infrastructure expansion and the investment that will be required to support the projected increases in natural gas production and demand. As a result, it is expected that the natural gas industry will be in a position to meet the challenge of providing the production and infrastructure expansion anticipated in the *AEO2000* projections.

Supply Availability

In the *AEO2000* reference case forecast, natural gas consumption increases by 1.8 percent a year between 1998 and 2020, and the projected demand in 2020, at 31.5 trillion cubic feet, exceeds the 1998 level by almost 50 percent. The challenge for the natural gas supply industry is whether adequate supplies will be available at the projected prices to meet the expected demand, which exceeds 30 trillion cubic feet by 2016. The historical record and current conditions suggest that the challenge can be met.

Uncertainty with regard to estimates of the Nation's natural gas resources has always been an issue in projecting production, and it is widely acknowledged that assessing actual resource levels is a difficult task. The *AEO2000* resource estimates (Figure 21) are based on assessments by the U.S. Geological Survey (USGS), Minerals Management Service (MMS), and National Petroleum Council (NPC). Some uncertainty is associated with each of the estimates. Because historical data are more limited for offshore fields, the uncertainty is higher for offshore than for onshore resources.

Figure 21. Technically recoverable U.S. natural gas resources as of January 1, 1998 (trillion cubic feet)



The uncertainty surrounding recoverable gas resource estimates is reflected in the differing views on the subject. For example, an April 1998 study by the Gas Research Institute (GRI), contending that the industry has "significantly underestimated" the growth potential of existing fields in the Midcontinent, onshore Gulf Coast, East Texas, and San Juan Basin areas, proposes higher reserve estimates for those areas. The USGS, MMS, and NPC estimates, however, are based on well documented and extensively reviewed methodologies and fall within the range of current expert opinion.

A key factor in making newer sources of production economical is the rate at which technology improvements will allow production from previously marginal sources without much higher prices. A few examples of significant technological advances in recent history include: (1) polycrystalline-diamond-compact drill bits, which are durable and versatile and are credited with significantly reducing the time required to drill a well; (2) measurement while drilling technology, which permits drilling and geologic information to be sent to the surface in real time; and (3) horizontal drilling, which exposes more reservoir rock to the wellbore.

The *AEO2000* reference case assumes that improvements in technology will continue at historical rates [*25*]. To assess the potential effects of faster and slower rates of improvement, rapid and slow technology cases are also examined (see "Market Trends," pages 78 and 79). Whereas the reference case projects total U.S. natural gas production in 2020 at 26.4 trillion cubic feet, the rapid technology case projects 28.1 trillion cubic feet of production in 2020, with the increase coming primarily from offshore and unconventional sources.

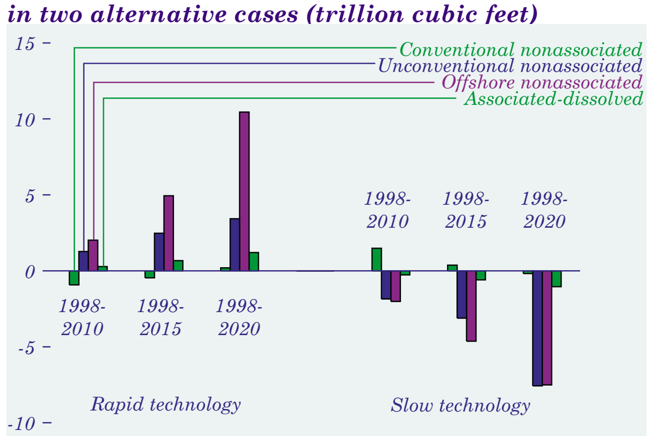
The offshore is an area that the industry hopes will provide considerable supplies in the future. Offshore gas production has increased somewhat in recent years, and larger increases are expected. Recent technological advances have made recovery from wells in progressively deeper waters possible (the record water depth has increased from 1,760 feet in 1989 for the Jolliet platform to 5,376 feet for the Mensa project, which began production in July 1997).

Offshore gas production in the Gulf of Mexico is expected to grow from 5.5 trillion cubic feet in 1998 to a peak of 6.7 trillion cubic feet in 2015 in the reference case. In the rapid technology case, however, offshore Gulf of Mexico production peaks at 7.7 trillion cubic feet in 2017, and cumulative offshore production between 1998 and 2020 is 148.3 trillion cubic feet, compared with 137.1 trillion cubic feet in the reference case. The rapid technology assumption has a similar but less dramatic, effect on unconventional gas recovery (UGR). Cumulative UGR production between 1998 and 2020 is 132.9 trillion cubic feet in the rapid technology case, compared with 129.5 trillion cubic feet in the reference case.

Technological progress makes it possible to produce more gas at lower cost from all sources. The projections of total annual production in 2010, 2015, and 2020 are lower in the slow technology case and higher in the rapid technology case than in the reference case. However, the effects of rapid technology improvement—lower costs and higher productivity—are greater for offshore and UGR production than for onshore conventional production, especially in the early part of the forecast (Figure 22). The reverse is true in the slow technology case.

The development of needed infrastructure in strategic areas is positioning the industry well to exploit its best opportunities for expanded production. Numerous pipeline expansion projects have recently been completed that greatly improve access to areas of growing production, such as the Midcontinent and the offshore, including seven projects completed in 1997 and 1998 that move offshore production to onshore Louisiana. They include the Destin Pipeline (1 billion cubic feet per day) and the Nautilus and Discovery projects (600 million cubic feet per day each). Also in 1997 and 1998, five gathering systems

Figure 22. Change from reference case projections of cumulative U.S. natural gas production in two alternative cases (trillion cubic feet)



were completed, linking offshore production platforms in the Gulf to the onshore.

The resource estimates used for *AEO2000* do not include areas in which drilling is restricted. Drilling moratoria have placed offshore areas in the eastern Gulf of Mexico, North Carolina, and California off limits, and drilling is limited in some areas of the West because of concern about emissions. There are also substantial resources in the Arctic National Wildlife Refuge (ANWR), where exploratory drilling is prohibited; however, the current inability to market natural gas from northern Alaska has rendered the ANWR accessibility issue moot.

Should it become economical to tap Alaskan gas resources, there is significant supply available outside the ANWR. Alaska's North Slope contains some 38 trillion cubic feet of technically recoverable natural gas in developed and known fields, and the 1995 USGS mean estimate for undiscovered Alaskan North Slope fields is 64 trillion cubic feet. Currently most of the North Slope gas production is being reinjected to enhance oil production. Of the 3.2 trillion cubic feet produced in 1998, 92 percent was reinjected. This resource is not being marketed at present, because the economics have not been favorable for the development of an infrastructure to transport the gas to market. Options for North Slope gas that are being considered include conversion to liquefied natural gas (LNG), the use of gas-to-liquids technology, and the development of pipelines to the lower 48 States.

Other areas of uncertainty include the availability of offshore rigs and skilled personnel. Employment in the oil and gas industries has fallen in recent years, as oil production has declined and productivity has increased. According to the Bureau of Labor Statistics, employment in the oil and gas extraction industries declined from an average of 400,000 employees in 1988 to an average of 340,000 in 1998, a reduction of 15 percent. Over the same period, total oil and gas production (excluding natural gas liquids) dropped by just 7 percent, from 34.9 quadrillion Btu to 32.6 quadrillion Btu, as rising productivity accelerated the decline in employment relative to the decline in production.

Although falling prices in 1998 led to layoffs in the extraction industry, preliminary Bureau of Labor Statistics estimates for September 1999 indicate that employment is now beginning to rise. Some potential employees may be reluctant to enter the workforce because of its cyclical history and the potential for future layoffs. Higher wages should provide sufficient incentive to attract workers, however, and there is ample time to develop a skilled workforce before the market reaches the projected demand level of 30 trillion cubic feet in 2015, given the economic incentives provided by rising prices.

Rig utilization was extremely high in 1997, averaging 86.9 percent overall. Offshore, virtually every available rig remained in use throughout the year. With declining prices in 1998, overall rig utilization dropped to 76.5 percent [*26*], alleviating the problem of rig availability, but the lower prices also slowed investment in the construction of new rigs. High capital requirements, as well as uncertainty about the actual demand for new rigs, currently are limiting investment in rig construction. Estimates of more than $100 million to upgrade an existing rig [*27*] and more than $300 million to construct a new deepwater semisubmersible rig [*28*] have been reported.

Price increases are a powerful incentive, however, for increased drilling and purchases of new equipment. Because the construction lead time for rigs is only 2 to 3 years, rig availability is unlikely to be a long-term issue between now and 2020, given the historical response to rising prices. The number of available drilling rigs increased by almost 16 percent annually between 1974 and 1982—from 1,767 to 5,644—as natural gas prices more than quadrupled in real terms. The rigs needed over the forecast period are assumed to be constructed, with the total rig count projected to increase from 1,705 in 1998 to 1,994 by 2020 [*29*].

A final key element in the supply outlook is the availability of imports, both pipeline imports from Canada and Mexico and LNG imports from foreign suppliers, such as Algeria, Australia, Trinidad and Tobago, and Qatar. The majority of the growth in imports in the *AEO2000* forecast comes from Canada, which has a resource base sufficient to increase both domestic consumption and exports significantly. The Canadian Gas Potential Committee estimated in 1997 that remaining discovered and undiscovered plays in the Western Canada Sedimentary Basin contained 184 trillion cubic feet of marketable gas.

Pipeline capacity has limited imports from Canada in the past, but new capacity has been and will continue to be built, as described above, making increased imports a likely contributor to increased supplies. In addition, drilling in new areas has the potential to increase Canada's exports still further. By the end of 1999, natural gas is expected to start flowing into the United States from the eastern Canadian Scotian Shelf, an area that has only begun to be tapped. In addition, interest in developing the MacKenzie Delta/Beaufort Sea region of the Northwest Territories has recently begun to increase. The Canadian National Energy Board estimates the undiscovered marketable potential for natural gas in the region at 55 trillion cubic feet. With most Canadian oil- and gas-producing regions less mature than those in the United States, the potential for additional low-cost production is strong, and imports from Canada remain competitive with U.S. domestic supplies in the forecast.

Mexico also has considerable natural gas resources that could be developed, and there is unused pipeline capacity from Mexico into the United States, although Mexico is expected to remain a net importer of U.S. natural gas. LNG imports, which have been constrained by their costs in the past, are becoming more economical and are projected to increase from 0.1 trillion cubic feet to 0.4 trillion cubic feet a year between 1998 and 2020. LNG offloading capacity has been expanded at the port facility in Everett, Massachusetts [*30*], and Southern LNG has applied to the Federal Energy Regulatory Commission to reactivate its mothballed facility on Elba Island, Georgia, to provide open-access service [*31*]. Thus, increased imports of LNG and natural gas imports from both Canada and Mexico could contribute to needed supply, over and above sufficient domestic production.

Overall, the natural gas industry is thought to be in a position to meet the supply requirements for a market of 30 trillion cubic feet, with adequate supplies available from numerous sources at the prices projected in the *AEO2000* reference case. As long as the industry remains confident that the demand will be there, the economic incentive of higher prices will assure that the necessary investments in infrastructure, rigs, drilling, and manpower will be made.

Petroleum: Gasoline and Diesel Fuel

Fuel Quality Changes

During the 1990s gasoline and diesel fuel were "reformulated" many times to meet requirements included in the Clean Air Act Amendments of 1990 (CAAA90) and other, State-initiated requirements (Table 5). Although the changes went unnoticed by most motorists, they required many adjustments at refineries and in fuel distribution systems. Refineries changed existing processes and invested in new ones, and storage and distribution systems were modified to handle additional products.

Table 5. Major fuel quality changes, past and future

Current	
1975	*Gasoline lead phaseout begins*
1989-1990	*Phase I summer gasoline volatility*
1992	*Oxygenated gasoline, wintertime*
	Phase II summer gasoline volatility
	California gasoline Phase I
1993	*Diesel sulfur reduction (500 ppm sulfur)*
	California diesel (500 ppm sulfur)
1995	*Phase I reformulated gasoline: simple model*
1996	*California cleaner gasoline Phase II*
1998	*Phase I reformulated gasoline: complex model*
2000	*Phase II reformulated gasoline*
2002	*California ban on MTBE*
Proposed	
2000-2003	*Removal of oxygen requirement on reformulated gasoline*
	Reduction of MTBE blended in gasoline
2002	*California cleaner gasoline Phase III, proposed*
2004-2007	*Reduced-sulfur gasoline, proposed 30 ppm*
Post-2007	*Ultra-low-sulfur diesel*

Note: Proposed regulations are not reflected in the AEO2000 reference case.

"Phase II" reformulated gasoline, which will be required in 2000, is the last fuel quality change specified by the CAAA90, but further changes are on the horizon. Two widely publicized fuel quality issues—sulfur removal and the reduction of the widely used gasoline additive methyl tertiary butyl ether (MTBE)—point to new challenges for the refining industry. The U.S. Environmental Protection Agency (EPA) is in the process of finalizing regulations that would severely restrict the sulfur content of gasoline and is proposing similar restrictions for diesel fuel. The State of California is already phasing MTBE out of gasoline, and there have been numerous proposals to restrict its use at the national level. Because it is current law, the California ban on MTBE is reflected in *AEO2000*. The proposed national MTBE and sulfur restrictions are not. To examine the potential impacts of the latter changes, two alternative cases, reflecting restrictions on fuel sulfur content and on MTBE blending, were prepared for this analysis.

Gasoline and Diesel Fuel Sulfur Reduction

In late 1999, the EPA is expected to finalize a rulemaking that would tighten restrictions on the amount of sulfur allowed in gasoline. Because gasoline sulfur and automotive emissions are linked, the rule will be issued in conjunction with the new "Tier 2" vehicle exhaust emissions standards that would take effect between model years 2004 and 2007 (see "Legislation and Regulations," page 13). Sulfur reduces the effectiveness of the catalyst used in the emissions control systems of advanced technology engines, increasing their emissions of hydrocarbons, carbon monoxide, and nitrogen oxides (NO_x). As a result, gasoline with significantly reduced sulfur levels will be required for the control systems to work properly and meet the new Tier 2 standards. In a Notice of Proposed Rulemaking (NPRM) published in May 1999, the EPA proposed lowering the average annual sulfur content of gasoline to 30 parts per million (ppm), which is about one-tenth the current national average.

Because the proposed Tier 2 emissions standards will apply to all vehicles, regardless of what type of fuel is used, the EPA is also planning to reduce the sulfur content of diesel fuel. Reduced-sulfur diesel fuel would enable diesel engine technologies, which are very sensitive to sulfur, to meet the new Tier 2 standards for NO_x and particulate matter (PM) emissions. Sulfur in all on-road diesel is currently restricted to 500 ppm, but engine manufacturers have indicated that new technologies will require sulfur contents of no more than 30 ppm [*32*]. The new standards may apply initially to diesel used for light-duty vehicles, which is only a small part of the market, and be extended to heavy-duty vehicle fuels at a later time.

Refinery Issues. Gasoline desulfurization is most often done in conjunction with a fluid catalytic cracking (FCC) unit that breaks down heavier crude oil components, which are often high in sulfur, into lighter gasoline streams. Sulfur reduction can be accomplished either by "hydrotreating" the feed going into the FCC unit or by desulfurizing the gasoline produced from the unit. Hydrotreating is a process that removes objectionable elements from the products or feedstocks by reacting them with hydrogen. Hydrotreating the inputs to the FCC unit improves the quality of the gasoline produced and reduces SO_x emissions from the FCC unit. It also improves the refineries' material balance and produces environmentally better diesel fuel [*33*]. However, this type of desulfurization is very capital intensive and requires treatment of a larger volume of feedstock and additional hydrogen-making capacity. Desulfurizing the gasoline output from the FCC unit is less capital intensive, allows smaller volumes to be treated, and consumes less hydrogen.

Recently developed technologies, such as CDTECH's CD HYDRO/HDS and Mobil's OCTGAIN processes, are variations on conventional hydrotreating applied to FCC gasoline that require less hydrogen. These technologies are not commercially proven, but they are expected to result in lower desulfurization costs than conventional hydrotreaters because they have lower operating and capital costs and produce gasoline with a higher octane than conventional hydrotreating. EPA originally pegged the cost of meeting a 40-ppm sulfur limit at 5.4 cents a gallon but now estimates that desulfurizing with newer technologies will cost only about 1.7 cents a gallon [*34*]. The American Petroleum Institute (API) has also cut its desulfurization cost estimate in half, from 5 cents a gallon to 2.5 cents a gallon, in view of the new technologies.

Because the new desulfurization technologies are not commercially proven, there is some concern that estimates of their operating costs and octane losses might be overly optimistic. Using less optimistic operating cost estimates for the new technologies, the API estimated that desulfurization costs could be as high as 3.3 cents a gallon [*35*]. A study done for DOE estimated the cost of the new technologies at an average of 2.9 cents a gallon [*36*]. The above cost estimates are single-year estimates in 1998 dollars and reflect full implementation of the sulfur regulations in 2004. The gasoline sulfur reduction sensitivity case provides cost estimates for years leading up to and after the change in regulations, with full implementation in 2007.

Regardless of the technology used, achieving the 30-ppm sulfur limit will be more difficult if recent proposals to waive the Federal oxygen requirement for reformulated gasoline are enacted (see discussion of MTBE below). Sulfur-free additives, such as MTBE, used to boost the oxygen content of reformulated gasoline, serve to dilute the sulfur content of the other gasoline components.

Gasoline Sulfur Reduction Sensitivity Case. The regulation for Tier 2 emissions standards and related sulfur reductions for gasoline has not been finalized and is therefore not included in the *AEO2000* reference case. The gasoline sulfur reduction case assumes a gasoline sulfur limit of 30 ppm, which is fully implemented by 2007. Reformulated gasoline is assumed to meet the 30-ppm limit by 2004. Conventional gasoline is initially allowed to meet a less stringent specification of 80 ppm but meets the 30-ppm limit by 2007. The more gradual sulfur reduction for conventional gasoline reflects a time extension for small and challenged refiners that is expected to be included in the final rule.

In order to reduce gasoline sulfur to the 30-ppm level, refiners will need to invest in conventional hydrotreating processes or in newly developed desulfurization processes that are potentially less costly but commercially unproven. Last year, the *Annual Energy Outlook 1999* (*AEO99*), included a national low-sulfur gasoline scenario that did not include new desulfurization technologies. In the *AEO99* automakers' national low-sulfur gasoline case, the cost of desulfurization using conventional processes was initially set at 8.3 cents a gallon in 2004, falling to 6.8 cents a gallon in 2010. Unlike the low-sulfur case in *AEO99*, this year's gasoline sulfur reduction case incorporates new desulfurization technologies.

The *AEO2000* sulfur reduction sensitivity case results in a national average gasoline price that is 2.3 cents a gallon higher that the reference case price in 2004, increasing to 3.9 cents a gallon higher when all gasoline is in compliance. The difference declines slightly, to 3.5 cents a gallon, by 2010. The alternative case results in additional capacity using hydroprocessing and new desulfurization technologies. Unlike cost estimates by EPA, API, and DOE mentioned above, which estimate the average cost of desulfurization, these estimates represent the desulfurization cost of the marginal barrel. In 2007, when all gasoline is assumed to meet the 30-ppm sulfur limit, cumulative refinery investment is $5.65 billion higher than in the reference case. Refineries invest even after 2007, in order to meet the sulfur limit in a growing gasoline market. By 2010 cumulative investment is $7.74 billion higher than in the reference case.

Restricted Use of the Gasoline Additive MTBE

MTBE became a widely used gasoline additive in the 1990s as a result of CAAA90 requirements to provide cleaner burning gasoline in some areas of the country. The use of MTBE to meet a requirement for 2.0 percent oxygen (by weight) in cleaner burning reformulated gasoline (RFG) has recently been called into question, because traces of MTBE have been found in 5 to 10 percent of the drinking water supplies in areas using RFG [*37*].

MTBE moves more quickly into water than do other gasoline components and has made its way from leaking pipes and underground storage tanks to water sources. MTBE has not been classified as a carcinogen, but it has been shown to cause cancer in animals. For the most part, MTBE found in water supplies has been well below levels of health concern, but it has become a big water quality issue because only trace amounts cause water to smell and taste bad. In 1999, water quality concerns resulted in the announcement by the Governor of California of a State-wide phaseout of MTBE, as well as numerous legislative proposals at both the State and Federal levels aimed at reducing or eliminating the use of MTBE in gasoline.

In response to rising concerns about the detection of MTBE in water supplies, the EPA convened a "Blue Ribbon Panel" (BRP) of experts early in 1999 to assess the extent of the problem and make recommendations. In a report submitted to the EPA in July [*38*], the BRP recommended a four-part plan that would protect water quality while maintaining the air quality benefits of RFG:

- A set of actions should be implemented to protect water supplies by enhancing programs for underground storage tanks, safe drinking water, and private well protection.
- The use of MTBE should be "substantially" reduced, and Congress should clarify the Federal and State authority to regulate the use of MTBE and other gasoline additives.
- To assure a cost-effective phasedown of MTBE, Congress should remove the current CAAA90 requirement that RFG contain 2 percent oxygen by weight.
- The EPA should identify a mechanism to ensure that current air quality benefits from RFG are not reduced.

The recommendations of the BRP are not binding, and it is unclear whether they will be implemented by Congress.

The *AEO2000* reference case reflects the California ban on MTBE but does not assume any changes in Federal legislation. The possible implications of a national reduction in MTBE blending were examined in a sensitivity case that reflects the recommendations of the BRP.

Refinery Issues. MTBE is an important blending component for RFG, used primarily as an oxygenate, a volume extender, and an octane enhancer. The EPA mandates a minimum oxygen content of 2.0 percent (by weight) in Federal RFG, primarily to reduce toxic exhaust emissions. To meet this requirement, MTBE is blended into RFG at approximately 11 percent by volume, with the added benefit of some important dilution effects. When MTBE is added to a gasoline blendstock, it replaces undesirable compounds such as benzene, aromatics, and sulfur. MTBE is also an effective octane enhancer. Its high octane helps offset the octane losses resulting from Federal restrictions on aromatics, benzene, and other gasoline components. If the use of MTBE in gasoline is reduced or banned, refiners will have to find other measures to maintain the octane level of gasoline while meeting the requirements for RFG. If the oxygen requirement is waived as suggested by the BRP, replacement of oxygen will not be a concern, but refiners will still need to make up for the MTBE volume and octane loss.

Legislation that would ban MTBE at either the national or State level without waiving the CAAA90 requirement for oxygen in RFG [*39*] would force the refining industry to find an alternative source of oxygen. Other EPA-approved oxygenates, including ethyl tertiary butyl ether (ETBE) and tertiary amyl methyl ether (TAME), would be suitable replacements; however, those ethers are similar to MTBE in some respects and could raise some of the same groundwater contamination concerns. Ethanol, which is currently used chiefly as an octane enhancer and volume extender in traditional gasoline, would be the leading candidate to replace MTBE. Ethanol is thought to be less toxic than ethers, has a high octane value, and enjoys a fair amount of political support at both the State and Federal levels.

The use of ethanol has some drawbacks, however, which must be considered. Compared with MTBE, ethanol contains more oxygen and is more volatile, resulting in higher emissions of smog-forming volatile organic compounds (VOCs). Because ethanol has a higher oxygen content than MTBE, only about half the volume is required to produce the same gasoline oxygen level. A gasoline volume loss results, because the other half of the displaced MTBE volume must come from other petroleum-based gasoline components. In addition, the relatively high volatility of ethanol limits its use in gasoline, because gasoline volatility, as measured by Reid vapor pressure (Rvp), is restricted depending on season and location. Ethanol's volatility also limits the use of other gasoline components, such as pentane, which are highly volatile and must be removed from gasoline to counterbalance the addition of ethanol. Finally, the "dilution effect" of ethanol is not as significant as that of MTBE, because the use of smaller volumes of ethanol is not as effective in diluting the undesirable qualities of the crude-base blending components [*40*].

The use of ethanol as a replacement for MTBE also poses some logistical problems. Gasoline blended with ethanol, unlike MTBE and other ethers, cannot be shipped in multi-fuel pipelines, because the moisture that is always present in pipelines and storage tanks causes the ethanol to separate from the gasoline. The petroleum-based gasoline components would have to be shipped separately and then blended with ethanol at a terminal as the product is loaded into trucks. Changes in the current infrastructure would have to be made to accommodate this type of terminal blending.

Ethanol supply is another issue, as current ethanol production capacity is not adequate to replace MTBE nationwide. The increase in demand should, however, cause ethanol prices to rise enough to make new ethanol facilities economically viable. Sufficient capacity could be in place depending on the timing of the MTBE ban. At present, ethanol supplies come primarily from the Midwest, where most of it is produced from corn feedstocks. Shipments to the West Coast and elsewhere via rail have been estimated to cost an additional 14.6 to 18.7 cents a gallon for transportation [*41*]. Ethanol use in the RFG program would displace its current usage in the Midwest as an extender and octane enhancer for traditional gasoline.

The BRP recommended that Congress eliminate the minimum oxygen requirement for RFG in order to dampen the effect of restrictions on MTBE use. If the oxygen requirement were removed, refiners would not have to replace the oxygen content provided by the MTBE. In addition, refiners would have more flexibility to meet RFG emissions reductions by blending alternatives such as alkylates, depending on an individual refinery's configuration and market conditions. The BRP suggested that the toxic standard on RFG be effectively tightened to maintain the current emissions level without an oxygenate requirement.

Producing RFG without ethanol or MTBE would require additional petroleum-based gasoline to make up for lost volume. In 1998, about 245,000 barrels of MTBE a day was blended into gasoline at U.S. refineries. If MTBE use were reduced from the current level of about 9 percent of RFG and oxygenated gasoline to 3 percent, about 165,000 barrels a day of relatively clean high-octane material might have to be replaced. The additional volumes are likely to consist of a combination of domestic production and imports.

The additional petroleum-based volumes would have to have more stringent specifications because of the loss of the dilution effect of oxygenates. As a result, alkylate would likely become a key blending component. Alkylate is an ideal blending component for RFG because it lacks benzene, other aromatics, olefins, and sulfur and has good octane and Rvp characteristics. The availability of large volumes of alkylate would require adjustments to refinery operations and capital expenditures to expand alkylation capacity. Petrochemical plants that are currently producing MTBE for sale to refineries could also convert their plants to produce alkylate.

Sulfur removal is another likely response to MTBE reduction, because the MTBE (and ethanol to a lesser extent) serve to dilute the sulfur content of the other gasoline components. Without MTBE the gasoline pool would have a higher sulfur content and might not meet NO_x emissions targets. Methods for desulfurizing gasoline are discussed above. If the currently proposed Tier 2 gasoline sulfur regulations are finalized, refiners will be forced to invest in sulfur removal to meet those standards.

BRP/MTBE Reduction Sensitivity Case. Based on the BRP recommendations, an alternative case was developed in which the oxygen requirement in gasoline was dropped and a cap was placed on the amount of MTBE in gasoline. In addition, the use of all ethers in gasoline was limited in the sensitivity case. The BRP noted that other ethers, such as ETBE and TAME, have similar but not identical characteristics and recommended "accelerated study of the health effects and groundwater characteristics of these compounds before they are allowed to be placed in widespread use." Because of such scrutiny, refiners and blenders are unlikely to increase the use of other ethers significantly.

Although the BRP did not specify a target level of MTBE, but only stated that its use should be reduced substantially, the level of MTBE and other ethers in gasoline was assumed in the sensitivity case to be limited to 3 percent by volume, which is consistent with MTBE in gasoline before the start of the RFG program. The elimination of the oxygen specification in RFG requires that other specifications be adjusted to maintain air quality. In order to maintain current air toxics emissions levels, as recommended by the BRP, the MTBE reduction case assumed tighter limits on benzene and sulfur in RFG than the reference case.

The projections for gasoline consumption and crude oil prices in the MTBE reduction sensitivity case are the same as in the reference case. The only changes relative to the reference case are gasoline specifications and the cap on ether use. The alternative case results in projected average gasoline prices that are between 1.3 and 1.4 cents a gallon higher than in the reference case between 2003 and 2005. RFG prices increase slightly more, starting at 2.8 cents a gallon in 2003 and dropping to 1.8 cents a gallon by 2005. The alternative case results in an additional 20,000 to 27,000 barrels a day of ethanol blending between 2003 and 2005 to offset some of the lost volume and octane associated with MTBE reduction. The alternative case also results in additional imports of gasoline and blending components, varying from 123,000 to 141,000 barrels a day between 2003 and 2005.

The pattern of refinery investment is different in the alternative case, with greater investment before 2003 and less thereafter. In 2003, cumulative investment is $2.43 billion more than in the reference case. The difference in cumulative investment narrows to $1.71 billion by 2005.

Energy Use: Appliance Efficiency Standards

Current Status

Since 1988, DOE has promulgated numerous efficiency standards requiring the manufacture of appliances that meet or exceed minimum levels of efficiency as set forth by DOE test procedures. In 1987, Congress passed the National Appliance Energy Conservation Act (NAECA), which permitted DOE to establish test procedures and efficiency standards for 13 consumer products. Under the auspices of NAECA, DOE is responsible for revising the test procedures and efficiency levels as technology and economic conditions evolve over time.

From 1988 to 1995, DOE established and revised efficiency standards almost on an annual basis, as shown in Table 6. In 1995, however, Congress issued a standards moratorium for fiscal year 1996, which prohibited DOE from establishing any new standards. The moratorium caused a delay of several years, with no standards becoming effective from 1996 through July 2000. After a reevaluation of the standards program, DOE established a new process that allows for greater input from stakeholders by creating the Advisory Committee on Appliance Energy Efficiency Standards, which comprises technical experts representing the concerns of industry, environmentalists, and the general public.

With input from stakeholders early in the promulgation process, it was believed that the rulemaking process would become more predictable, more timely, and less controversial. The refrigerator standard issued for July 2001, for example, was promulgated through a series of compromises in December 1996, allowing a later enforcement date but at a higher efficiency level. Achieving similar consensus among

Table 6. Effective dates of appliance efficiency standards, 1988-2001

Product	1988	1990	1992	1993	1994	1995	2000	2001
Clothes dryers	X				X			
Clothes washers	X				X			
Dishwashers	X				X			
Refrigerators and freezers		X		X				X
Kitchen ranges and ovens		X						
Room air conditioners		X					X	
Direct heating equipment		X						
Fluorescent lamp ballasts		X						
Water heaters		X						
Pool heaters		X						
Central air conditioners and heat pumps			X					
Furnaces								
Central (>45,000 Btu per hour)			X					
Small (<45,000 Btu per hour)			X					
Mobile home		X						
Boilers			X					
Fluorescent lamps, 8 foot					X			
Fluorescent lamps, 2 and 4 foot (U tube)						X		

disparate concerns such as the gas and electric industries and environmentalists may prove difficult, however, when multi-fuel products, such as water heaters, are considered for review. The debate over end-use efficiency versus total system efficiency is a lively one, with electric and gas concerns generally disagreeing as to how efficiency and environmental benefits should be measured. In fact, the inability to create a single national home energy rating system (HERS) has shown that achieving consensus among these groups is difficult, signaling a continued debate as to how efficiency should be evaluated across fuel types.

Currently, DOE is in the process of evaluating new efficiency standards for several products. The schedule calls for final rules to be established for water heaters in June 2000, clothes washers in December 2000, and central air conditioners and heat pumps in April 2001. After the final rules are published in the *Federal Register*, a lead time of 3 to 5 years is required for the standards to take effect. Because the *AEO2000* reference case includes only standards that have been finalized, with the effective dates and efficiency levels specified in the *Federal Register*, no new efficiency standards are included in the projections.

An agreement between manufacturers and energy efficiency advocates was reached in October 1999 on fluorescent lighting standards for commercial and industrial applications. Still subject to a final rulemaking by DOE, the new efficiency standards for electronic ballasts are not included in the reference case. Less efficient magnetic ballasts are projected to make up 6 percent of new and replacement fluorescent lighting sales in the commercial sector in the reference case at the time the standards are expected to go into effect on April 1, 2005. The next products DOE intends to evaluate for standards include distribution transformers, commercial furnaces and boilers, commercial heat pumps and air conditioners, and commercial water heaters.

Appliance Standards Sensitivity Cases

To examine the potential impacts of future appliance efficiency standards on energy consumption in the residential and commercial sectors, two cases were analyzed in which it was assumed that DOE would effectively promulgate standards for most appliances on a regular basis. For these cases, near-term efficiency levels and effective dates were based on a report by the American Council for an Energy-Efficient Economy (ACEEE), *Approaching the Kyoto Targets: Five Key Strategies for the United States*

[*42*]. Because the schedule for implementation of some of the standards in the near term has changed since the ACEEE report was published, the effective dates assumed for some products differ from those in the report. In addition, it was assumed that DOE would revise the standards every 8 years, increasing the efficiency level by 10 percent and 20 percent in the two cases, if technologically feasible. It was further assumed that major shifts in technology—including heat-pump water heaters and horizontal-axis washing machines—would not be subject to the standards. Table 7 shows the products and dates for the standards assumed in the two sensitivity cases.

Figure 23 shows the cumulative primary energy saved from the standards listed in Table 7 through 2020, the end of the forecast horizon. Because the sensitivity cases do not include changes in the fuel mix for electricity generation, the conversion from delivered electricity to primary energy is the same as that in the reference case. Overall, more than 11 quadrillion Btu of energy is saved cumulatively through 2020 in the 10-percent standards case, nearly one-half of the projected energy consumption in the residential sector in 2020. In the 20-percent standards case, more than 12 quadrillion Btu of energy is saved cumulatively through 2020. However, because the near-term standards account for the majority of the savings and many technologies reach their technological limits before achieving the 20-percent efficiency increase, the incremental savings seen when the 20-percent standards case is compared with the 10-percent case are less than those seen when the 10-percent case is compared with the reference case.

Electricity-related energy savings, including reductions in conversion losses, account for nearly 78 percent of the cumulative savings by 2020 in the 20-percent standards case. The decrease in the amount of electricity generated throughout the forecast reduces carbon emissions by more than 17 million metric tons in 2020 (3.5 percent) and by nearly 163 million metric tons cumulatively through 2020. The residential sector accounts for 60 percent of the cumulative energy savings, with the majority of the savings attributable to the standards for water heaters and air conditioners. For the commercial sector, fluorescent lighting standards contribute the most to the reduction in energy use in both cases.

Figure 23. Cumulative energy savings from appliance standards by fuel in two cases, 2003-2020 (quadrillion Btu)

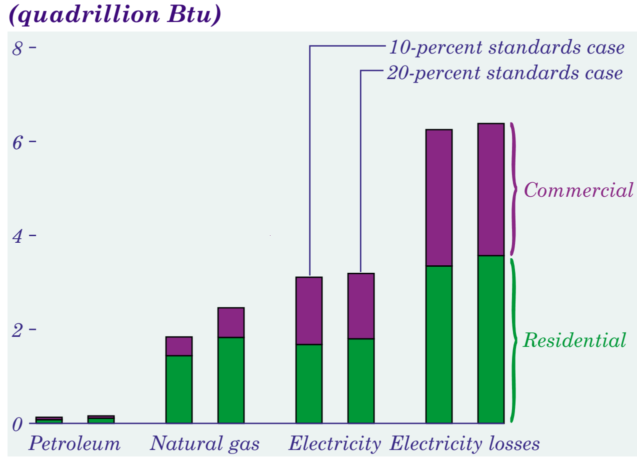


Table 7. Projected effective dates of appliance efficiency standards, 2003-2020

Product	2003	2005	2006	2008	2009	2011	2013	2016	2017	2019
Clothes dryers					X					
Clothes washers			X							
Dishwashers					X				X	
Refrigerators and freezers					X					
Kitchen ranges and ovens					X					
Room air conditioners					X				X	
Fluorescent lamp ballasts	X									
Water heaters	X					X				X
Central air conditioners and heat pumps		X					X			
Fluorescent lamps						X				
Commercial furnaces and boilers				X				X		
Commercial air conditioners and heat pumps				X				X		
Commercial water heaters				X				X		

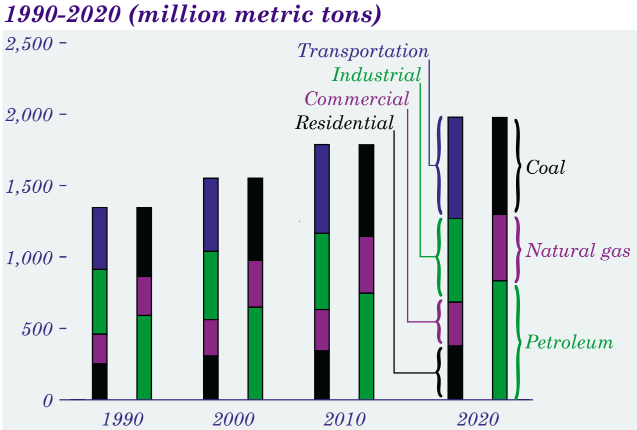
Carbon Emissions in *AEO2000*

Reference Case

In the *AEO2000* reference case, carbon emissions from energy consumption are expected to reach 1,552 million metric tons in 2000, 15 percent above the 1990 level of 1,345 million metric tons. The projected emissions continue to rise to 1,787 million metric tons in 2010 and 1,979 million metric tons in 2020, 33 percent and 47 percent above the 1990 levels, respectively (Figure 24). Total emissions increase at an average annual rate of 1.3 percent between 1998 and 2020, and per capita emissions also increase at an average rate of 0.5 percent a year.

Carbon emissions rise throughout the projection period, because continued economic growth and moderate increases in energy prices are expected to lead to increasing energy consumption. The 1.3-percent growth rate for emissions is faster than for total energy consumption, which increases at an average annual rate of 1.1 percent, for two primary reasons. First, approximately 41 percent of nuclear generating capacity (which is carbon free) is retired by 2020, and no new nuclear plants are constructed. Second, continued moderate prices for both natural gas and coal lead to slow growth in renewable energy use.

Figure 24. U.S. carbon emissions by sector and fuel, 1990-2020 (million metric tons)



In 2020, electricity generation accounts for 38 percent of all carbon emissions, up from 37 percent in 1998. The increasing share of carbon emissions from generation results, in part, from the 1.4-percent annual growth rate in electricity consumption. Of the new capacity required to meet electricity demand growth and to replace the loss of nuclear capacity, about 7 percent is fueled with coal and 90 percent with natural gas.

The growth of energy consumption and carbon emissions in the transportation sector is faster than in the other end-use sectors because of increased travel and the slow improvement in fuel efficiency in the reference case. Between 1998 and 2020, transportation energy demand and carbon emissions both grow at an average annual rate of 1.7 percent, and in 2020 the transportation sector accounts for 36 percent of all carbon emissions. The average efficiency of the light-duty vehicle fleet—cars, light trucks, vans, and sport utility vehicles—remains essentially unchanged between 1998 and 2020. Over the same period, vehicle-miles traveled by light-duty vehicles increase by 1.7 percent a year, faster than the growth rate for the over-age-16 population (0.9 percent a year). Growth in both air and freight travel, at average rates of 4.0 percent and 1.5 percent a year, also contributes to the increase in emissions from the transportation sector.

Emissions from the residential and commercial sectors grow by 1.3 percent and 1.2 percent a year, respectively, contributing 19 percent and 16 percent of carbon emissions in 2020 (including emissions from the generation of electricity used in each sector). Continued growth in energy service demand, particularly in electricity-using equipment and appliances, results in the emissions increases, offset somewhat by efficiency improvements in both sectors. Industrial sector emissions increase by only 0.9 percent a year through 2020 and account for 30 percent of the emissions in 2020 (including emissions from electricity generation for the sector). The relatively low growth rate results from efficiency improvements, small growth in coal use for boiler fuel, and a shift to less energy-intensive industries.

By fuel, petroleum products are the leading source of energy-related carbon emissions because of the continuing growth of the transportation sector, which is heavily dependent on petroleum. About 42 percent of all emissions, or 833 million metric tons of the total of 1,979 million metric tons in 2020, are from petroleum products, and about 82 percent of the petroleum emissions are from transportation uses.

Coal is the second leading source of carbon emissions at about 34 percent, or 680 million metric tons, in 2020. Coal has the highest carbon content of all the fossil fuels and remains the predominant fuel source for electricity generation. By 2020, the share of coal-fired generation, excluding cogeneration, declines slightly from its 1998 level of 55 percent but still accounts for 52 percent of all generation. About 90 percent of carbon emissions from coal in 2020 result from electricity generation.

Natural gas consumption for both electricity generation and direct end uses grows the fastest of all the fossil fuels—at a rate of 1.8 percent a year through 2020. Natural gas has a relatively low carbon content relative to other fossil fuels (only about half that of coal), and thus carbon emissions from natural gas use are projected to be just 464 million metric tons in 2020, about 23 percent of the total.

Macroeconomic Growth

The assumed rate of economic growth has a strong impact on the projection of energy consumption and, therefore, carbon emissions. In *AEO2000*, the high economic growth case includes higher growth in population, the labor force, and labor productivity, resulting in higher industrial output, lower inflation, and lower interest rates. As a result, GDP increases at an average rate of 2.6 percent a year from 1998 to 2020, compared with a growth rate of 2.2 percent a year in the reference case.

With higher macroeconomic growth, energy demand grows faster, as higher manufacturing output and higher income increase the demand for energy services. Total energy consumption in the high economic growth case is 129.4 quadrillion Btu in 2020, compared with 120.9 quadrillion Btu in the reference case. As a result of the higher consumption, carbon emissions are 2,126 million metric tons, or 7 percent, higher than the reference case level of 1,979 million metric tons in 2020.

In the low economic growth case, assumptions of lower growth in population, the labor force, and labor productivity result in an average annual growth rate of 1.7 percent through 2020. With lower economic growth, energy consumption in 2020 is reduced from 120.9 quadrillion Btu to 113.3 quadrillion Btu, and carbon emissions are 1,851 million metric tons, or 6 percent, lower than in the reference case.

Total energy intensity, measured as primary energy consumption per dollar of GDP, improves at a faster rate in the high economic growth case, partially offsetting the changes in energy consumption caused by the higher growth assumptions. With more rapid growth in energy consumption, there is greater opportunity to turn over and improve the stock of energy-using technologies, increasing the overall efficiency of the capital stock. Aggregate energy intensity in the high economic growth case decreases at a rate of 1.2 percent a year from 1998 through 2020, compared with 1.1 percent in the reference case and 0.8 percent in the low economic growth case.

Technology Improvement

The *AEO2000* reference case includes continued improvements in technology for both energy consumption and production: improvements in building shell efficiencies for both new and existing buildings; efficiency improvements for new appliances and transportation vehicles; productivity improvements for coal production; and improvements in the exploration and development costs, finding rates, and success rates for oil and gas production. As a result of continued improvements in the efficiency of end-use and electricity generation technologies, total energy intensity in the reference case declines at an average annual rate of 1.1 percent between 1998 and 2020.

The projected decline in energy intensity is considerably less than that experienced during the 1970s and early 1980s, when energy intensity declined, on average, by 2.2 percent a year. Approximately half of that decline can be attributed to structural shifts in the economy—shifts to service industries and other less energy-intensive industries; however, the rest resulted from the use of more energy-efficient equipment. During those years there were periods of rapid escalation in energy prices, encouraging some of the efficiency improvements. Then, as energy prices moderated, the improvement in energy intensity moderated. Between 1986 and 1998, energy intensity declined at an average annual rate of 1.0 percent.

Regulatory programs have contributed to some of the past improvements in energy efficiency, including the Corporate Average Fuel Economy standards for light-duty vehicles and standards for motors and energy-using equipment in buildings in the Energy Policy Act of 1992 and the National Appliance Energy Conservation Act of 1987. In keeping with the general practice of incorporating only current policy and regulations, the reference case for *AEO2000* assumes no new efficiency standards. Only current standards or approved new standards with specified levels are included.

Technology improvements in energy-consuming equipment could reduce energy consumption and energy-related carbon emissions to levels below those in the reference case. Conversely, slower improvements could increase both consumption and emissions. *AEO2000* presents a range of alternative cases that vary key assumptions about technology improvement and penetration.

In the end-use demand sectors, experts in technology engineering were consulted to derive high technology assumptions, considering the potential impacts of increased research and development for more advanced technologies. The revised assumptions included earlier years of introduction, lower costs, higher maximum market potential, and higher efficiencies than in the reference case. It is possible that further technology improvements could occur if there were a very aggressive research and development effort. For the electricity generation sector, the cost and efficiencies of advanced fossil-fired and new renewable generating technologies were assumed to improve from reference case values [*43*].

The low technology case assumes that all future equipment choices are from the equipment and vehicles available in 2000, with new building shell and industrial plant efficiencies frozen at 2000 levels. New generating technologies are assumed not to improve over time. Aggregate efficiencies still improve over the forecast period as new equipment is chosen to replace older stock and the capital stock expands. Also, building shell efficiencies improve with price increases.

In the high technology case, with the high technology assumptions for all four end-use demand sectors and the electricity generation sector combined, aggregate energy intensity declines at an average of 1.4 percent a year from 1998 to 2020, compared with 1.1 percent a year in the reference case (Figure 25). In the 2000 technology case, the average decline is only 0.9 percent a year through 2020. Total energy consumption increases to 112.6 quadrillion Btu in 2020 in the high technology case, compared with 120.9 quadrillion Btu in the reference case (Figure 26), but increases to 126.3 quadrillion Btu in the 2000 technology case.

The lower energy consumption in the high technology case lowers carbon emissions from 1,979 million metric tons in the reference case in 2020 to 1,820 million metric tons (Figure 27). In the 2000 technology case, emissions increase to 2,080 million metric tons

Figure 25. U.S. energy intensity in three cases, 1998-2020 (thousand Btu per dollar GDP)

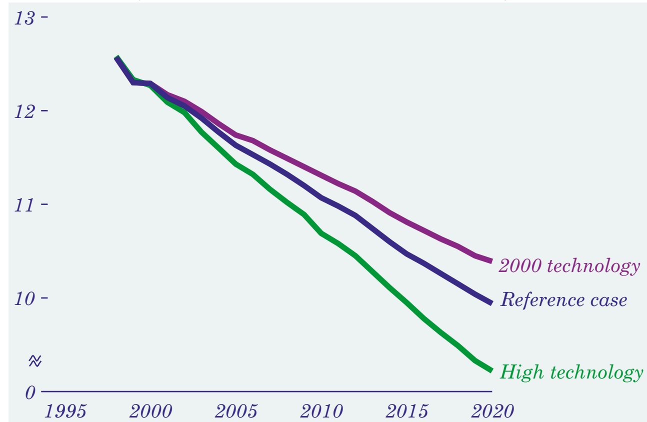


Figure 26. U.S. energy consumption in three cases, 1998-2020 (quadrillion Btu)

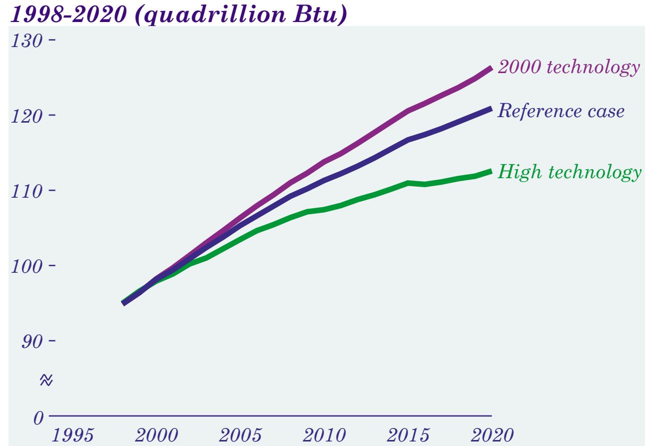
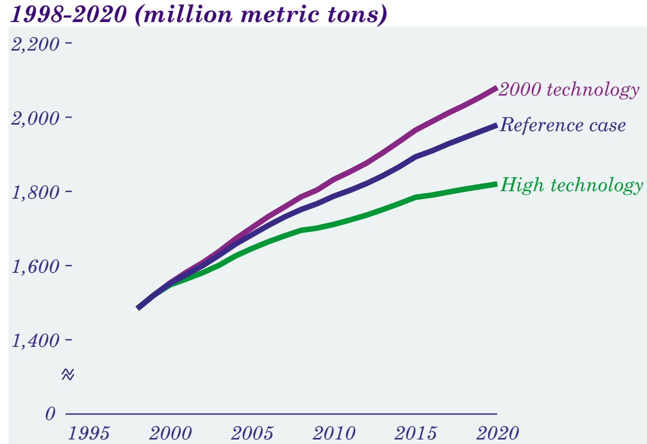


Figure 27. U.S. carbon emissions in three cases, 1998-2020 (million metric tons)



in 2020. About 38 percent, or 60 million metric tons, of the reduction in carbon emissions in the high technology case compared to the reference case results from lower electricity demand and generation. An additional 72 million metric tons of the reduction, or 45 percent, results from shifts to more efficient or alternative-fuel vehicles in the transportation sector.

The high technology assumptions themselves do not guarantee acceptance and penetration in the market. Technologies must still be cost-effective as judged by the consumers, and penetration can be slowed by the relative turnover of the capital stock. In order to encourage more rapid penetration of advanced technologies, to reduce energy consumption or carbon emissions, it is likely that either market policies (for example, higher energy prices) or non-market policies (for example, new standards) may be required.

The Kyoto Protocol

From December 1 through 11, 1997, representatives from more than 160 countries met in Kyoto, Japan, at the third session of the Conference of the Parties to the 1992 Framework Convention on Climate Change. Although the Framework Convention called for the developed countries to undertake actions to reduce greenhouse gas emissions to 1990 levels by 2000, the goal of the Conference was the negotiation of binding limits for greenhouse gas emissions for the developed nations. In the resulting Kyoto Protocol to the Framework Convention, targets for greenhouse gas emissions were established for the developed nations—the Annex I countries [*44*]—relative to their emissions levels in 1990. The targets are to be achieved, on average, from 2008 through 2012, the first commitment period in the Protocol.

The overall emissions reduction target for the Annex I countries is 5.2 percent below 1990 levels. Relative to 1990, the individual targets range from an 8-percent reduction for the European Union (EU) to a 10-percent increase for Iceland. Australia and Norway are also allowed increases of 8 percent and 1 percent above 1990 levels, respectively, while New Zealand, the Russian Federation, and the Ukraine are held to their 1990 levels. Other Eastern European countries undergoing transition to a market economy have reduction targets between 5 percent and 8 percent below 1990 levels. The reduction target for Canada and Japan is 6 percent and for the United States 7 percent below 1990 levels. Non-Annex I countries have no targets under the Protocol, although the Protocol reaffirms the commitments of the Framework Convention by all parties to formulate and implement climate change mitigation and adaptation programs.

The Protocol was opened for signature on March 16, 1998, for a 1-year period. It will enter into force 90 days after 55 Parties, including Annex I countries accounting for at least 55 percent of the 1990 carbon dioxide emissions from Annex I nations, have deposited their instruments of ratification, acceptance, approval, or accession. By March 15, 1999, 84 countries had signed the Protocol, including all but two of the Annex I countries, Hungary and Iceland. The Annex I signatories accounted for more than 99 percent of Annex I carbon emissions in 1990, not including the emissions from Belarus and Turkey. As of October 12, 1999, 16 countries had ratified or acceded to the Protocol—Antigua and Barbuda, Bahamas, Cyprus, El Salvador, Fiji, Georgia, Guatemala, Jamaica, the Maldives, Micronesia, Niue, Panama, Paraguay, Trinidad and Tobago, Tuvalu, and Uzbekistan.

Although the Protocol does not prescribe specific steps to be taken, a number of potential actions are enumerated. They include energy efficiency improvements, enhancement of carbon-absorbing sinks, research and development of sequestration technologies, phasing out of fiscal incentives and subsidies that may inhibit the goal of emissions reductions, and reduction of methane emissions in waste management and in energy production, distribution, and transportation. Sources of emissions include energy combustion, fugitive emissions from fuels, industrial processes, solvents, agriculture, and waste management and disposal.

Energy use is naturally a focus of greenhouse gas reductions. In 1990, total greenhouse gas emissions in the United States were 1,641 million metric tons carbon equivalent, of which carbon emissions from the combustion of energy comprised 1,345 million metric tons, or 82 percent. By 1998, total greenhouse gas emissions had risen to 1,803 million metric tons carbon equivalent, with 1,485 million metric tons (82 percent) from energy combustion [*45*]. Because energy-related carbon emissions constitute such a large percentage of total greenhouse gas emissions, any action or policy to reduce emissions will affect U.S. energy markets.

The Kyoto Protocol includes a number of flexibility measures for compliance—often referred to as *what*, *where*, and *when* flexibility. *What* flexibility refers to the source of the emissions. Although carbon dioxide is the major greenhouse gas in terms of the level of emissions, the Protocol includes methane, nitrous oxide, hydrofluorocarbons, perfluorocarbons, and sulfur hexafluoride [*46*], in addition to carbon dioxide. The aggregate target is established using the carbon dioxide equivalent of each of the greenhouse gases, based on the global warming potential of each gas. Carbon-absorbing sinks—forests, other vegetation, and soils—are also included in *what* flexibility. Net changes in emissions by direct anthropogenic land-use changes and forestry activities will be used in meeting the commitment, limited to afforestation, reforestation, and deforestation since 1990. Specific guidelines and rules for the accounting of land-use and forestry activities must be resolved by the Conference of the Parties.

Where flexibility includes a variety of international activities, which would allow a country to meet its emissions target by taking action with or within other countries. Emissions trading among the Annex I countries is permitted. Groups of Annex I countries, such as the EU, may also jointly meet the total commitment of all the member nations either by allocating a share of the total reduction to each member or by trading emissions rights. Joint implementation projects are also allowed among the Annex I countries, allowing a nation to take emissions credits for projects that reduce emissions or enhance emissions-absorbing sinks in other Annex I countries. It is specifically indicated in the Protocol that trading and joint implementation are supplemental to domestic actions.

The Protocol also establishes a Clean Development Mechanism (CDM), a program under which Annex I countries can earn credits for projects that reduce emissions in non-Annex I countries. Such projects must lead to measurable, long-term benefits. Reductions from projects occurring from 2000 up to the beginning of the first commitment period can be used to assist in compliance in the commitment period. An executive board will be established to supervise the CDM, and an unspecified share of the proceeds from certified project activities will be used to cover administrative expenses and to assist developing country Parties that are particularly vulnerable to adverse effects of climate change to meet the costs of adaptation.

Under *when* flexibility, the targets can be achieved on average over the first commitment period of 2008 to 2012 rather than in each individual year. Averaging emissions over the 5-year period smooths out short-term fluctuations that might result from economic cycles or weather conditions. No targets are established for periods after 2012, although the Conference of the Parties will initiate consideration of future commitments at least 7 years before the end of the first commitment period. Banking—carrying over emissions reductions that go beyond the target from one commitment period to some subsequent commitment period—is allowed. The Protocol indicates that each Annex I country must have made demonstrable progress in achieving its commitments by 2005.

At the fourth session of the Conference of the Parties in Buenos Aires, in November 1998, a plan of action was adopted to finalize a number of the implementation issues at the sixth Conference of the Parties, which is likely to be held late in 2000 or early in 2001. Also at issue is the possibility of limiting the amount of credits received through international actions that may be used to meet a country's target.

EIA's Analysis of the Kyoto Protocol

In 1998, at the request of the U.S. House of Representatives Committee on Science, EIA analyzed the likely impacts of the Kyoto Protocol on U.S. energy prices, energy use, and the economy in the 2008 to 2012 period, using the same methodologies and assumptions that were used for the *Annual Energy Outlook 1998* (*AEO98*) [*47*], the latest *AEO* at the time. The analysis was published in *Impacts of the Kyoto Protocol on U.S. Energy Markets and Economic Activity* [*48*], with an accompanying briefing report, *What Does the Kyoto Protocol Mean to U.S. Energy Markets and the U.S. Economy?* [*49*].

In 1999, the Committee on Science requested that EIA analyze the impacts of an earlier phased-in start date for U.S. carbon emissions reductions based on the original analysis of the Kyoto Protocol, with only those changes in assumptions caused by the early start date. Earlier carbon reductions could lead to the purchase of more efficient or less carbon-intensive equipment at an earlier date, making it easier and less expensive to meet greenhouse gas emissions targets. The resulting analysis, *Analysis of the Impacts of an Early Start for Compliance with the Kyoto Protocol* [*50*], was published in July 1999.

Because of the uncertainties surrounding the final implementation of the Kyoto Protocol, EIA's analysis of the Protocol included a range of six cases with different levels of reductions for domestic energy-related carbon emissions. EIA assumed that the United States would reach its goal of a 7-percent reduction in net greenhouse gas emissions in each of the carbon reduction cases, but each case implicitly assumed different levels of forestry and agricultural sinks, reductions from other greenhouse gases, international trading, and other international activities, which may offset the domestic reductions required from carbon. Each of the cases with higher carbon targets (smaller reductions) assumed more contribution from sinks, other gases, and international activities to offset carbon reductions.

- **Reference Case.** Carbon emissions from energy increase to 33 percent above 1990 levels in 2010, reaching 1,791 million metric tons compared to 1,345 million metric tons in 1990. Between 2008 and 2012, carbon emissions from energy average 1,792 million metric tons.

- **24 Percent Above 1990 Levels (1990+24%).** Carbon emissions from energy increase to an annual average of 1,670 million metric tons between 2008 and 2012, 24 percent above the 1990 levels, reducing carbon emissions from energy by an average of 122 million metric tons below the reference case during that period. International activities and net offsets from carbon-absorbing sinks and other gases account for the remaining reductions of 420 million metric tons, nearly 80 percent of the total net greenhouse gas reduction.

- **14 Percent Above 1990 Levels (1990+14%).** Carbon emissions from energy average 1,539 million metric tons annually between 2008 and 2012, which is approximately the level estimated for 1998 in *AEO98*, and is 14 percent above 1990 levels. This requires the average annual carbon emissions from energy to be reduced by 253 million metric tons between 2008 and 2012. International activities and net offsets from carbon-absorbing sinks and other gases account for the remaining reductions of 289 million metric tons.

- **9 Percent Above 1990 Levels (1990+9%).** Carbon emissions from energy increase to an annual average of 1,467 million metric tons between 2008 and 2012, 9 percent above 1990 levels, an average reduction in energy-related carbon emissions of 325 million metric tons from the reference case projection. International activities and net offsets from carbon-absorbing sinks and other gases account for the remaining reductions of 217 million metric tons.

- **Stabilization at 1990 Levels (1990).** Carbon emissions from energy are stabilized at the 1990 level, averaging 1,345 million metric tons during the commitment period of 2008 through 2012, a reduction of 447 million metric tons in energy-related carbon emissions from the reference case. International activities and net offsets from carbon-absorbing sinks and other gases account for the remaining reductions of 95 million metric tons.

- **3 Percent Below 1990 Levels (1990-3%).** Carbon emissions from energy are reduced to an annual average of 1,307 million metric tons between 2008 and 2012, a reduction of 485 million metric tons in energy-related carbon emissions from the reference case. International activities and net offsets from carbon-absorbing sinks and other gases account for the remaining reductions of 57 million metric tons.

- **7 Percent Below 1990 Levels (1990-7%).** Carbon emissions from energy are reduced to an annual average of 1,250 million metric tons in the period 2008 to 2012, a reduction of 542 million metric tons in energy-related carbon emissions relative to the reference case. This case essentially assumes that the 7-percent target in the Kyoto Protocol for reducing emissions below 1990 levels must be met by energy-related carbon emissions with no net offsets from sinks, other greenhouse gases, or international activities.

In each of the carbon reduction cases, the target is achieved on average for each of the years in the first commitment period, 2008 through 2012. The target is assumed to be constant from 2013 through 2020, the end of the forecast horizon, because the Protocol does not specify any targets beyond the first commitment period, although consideration of commitments for subsequent periods will be initiated at least 7 years before the end of the first commitment period, i.e., prior to 2005.

In the 1998 study, the target was assumed to be phased in over a 3-year period beginning in 2005, because the Protocol indicates that demonstrable progress toward reducing emissions must be shown by 2005. This allows energy markets to begin adjustments to meet the reduction targets 3 years prior to 2008. In the 1999 analysis of an earlier start date for emissions reductions, the Committee requested that EIA analyze the impact of a start date of 2000, instead of 2005, reaching the same emissions target during the commitment period 2008 through 2012, using the 1990+24%, 1990+9%, and 1990-7% cases from the earlier study.

Both analyses assumed that a carbon price would be applied to each of the energy fuels at its point of consumption, relative to its carbon content. The carbon price would not be applied directly to electricity but would be applied to the fossil fuels used for electricity generation and reflected in the delivered price of electricity. The carbon price represents the marginal cost of reducing domestic carbon emissions, reflecting the price the United States would be willing to pay to purchase carbon permits from other countries or to induce carbon reductions in other countries. It does not represent the international market-clearing price of carbon permits or the price at which other countries would be willing to offer permits. The analyses also assumed that a carbon permit trading system would function as a Federal Government auction, and that the revenues collected by the Government would be recycled to the economy through either a lump sum rebate in personal income taxes or a reduction in social security tax rates.

The most significant results of both studies are:

- Higher energy prices, as a result of the carbon price, and their impact on the U.S. economy will encourage fuel switching and reductions in energy consumption. Consumers will reduce energy consumption by reducing demand for energy services and purchasing more efficient equipment.

- With a start date of 2005 for carbon emissions reductions, the carbon price necessary to reduce U.S. energy-related carbon emissions to the required level ranges from $67 to $348 per metric ton (1996 dollars) in 2010. Imposing carbon prices before 2005 reduces energy consumption and carbon emissions in that period by encouraging earlier efficient improvements, accelerated retirements of less efficient equipment, and the acceleration of technology improvements. The early start date reduces the carbon price in 2010 for each of the carbon reduction cases (Figure 28), and average carbon prices over the first commitment period, 2008 through 2012, are also lowered (Figure 29). However, because carbon prices are incurred earlier, average carbon prices over the entire projection period, 2000 through 2020, increase with the early start date.

- With a 2005 start date for carbon reductions, the average price of electricity increases by between 20 and 86 percent across the various cases. The price increases by between 19 and 76 percent with a start date of 2000. In all cases, the electricity generation sector accounts for most of the carbon reductions, as a result of lower electricity demand, improved generating efficiency, and, primarily, fuel switching.

- Because coal is the most carbon-intensive of the fossil fuels, the price of coal will increase more than the prices of other fossil fuels as a result of the carbon price, and coal use, particularly for electricity generation, will be sharply reduced (by between 18 and 78 percent in 2010). If the carbon price increases to its highest level, the use of coal for generation may nearly disappear by 2020 in the more stringent reduction cases.

Figure 28. Projected carbon prices in six cases, 2010 (1996 dollars per metric ton)

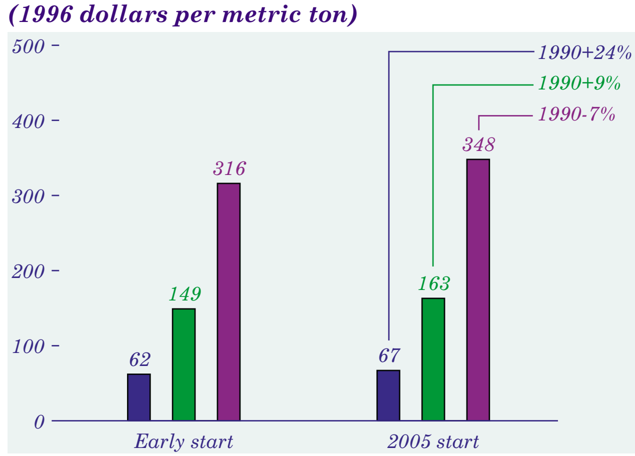
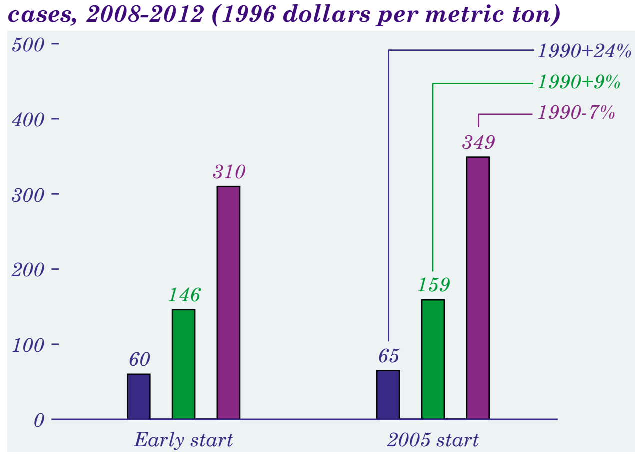


Figure 29. Average projected carbon prices in six cases, 2008-2012 (1996 dollars per metric ton)



- Coal-fired electricity generation will be replaced by generation from natural gas and renewables and also by the continued operation of many existing nuclear plants. Increases in natural gas generation will more than offset reductions in natural gas use by residential, commercial, and industrial consumers. Renewable technologies, particularly biomass and wind, become economical with high fossil fuel prices. It also becomes economical to extend the operating lives of existing nuclear plants rather than retire them.

- With a start date for carbon reductions of 2005, the average price of motor gasoline will increase by between 11 percent and 53 percent across the various cases. With a start date of 2000, the price increases range between 10 percent and 46 percent. With the higher prices of motor gasoline and other transportation fuels, travel will be lower and vehicle efficiency will be higher in all cases compared with the reference case.

- As a result of the carbon prices and higher energy prices, the growth in U.S. gross domestic product (GDP) will be lower than in the reference case during the transition period; however, the economy will continue to grow. As carbon prices decline and the economy adjusts, GDP will rebound by 2020 to about the level in the reference case. With an earlier start date, the economy experiences a loss in GDP beginning in 2000; however, the early start date smooths the transition of the economy to the longer run target. Potential GDP losses [*51*] begin in 2000 in the early start case at a slower rate than with the 2005 start date (Figure 30). Once in the compliance period, potential GDP takes on the same path in both cases. The loss in actual GDP in the early start cases between 2000 and 2005 is between one-half and nearly three-quarters of the loss in the cases with the 2005 start date between 2005 and 2010. By 2010, in the 1990+24% case with the early start date, the GDP loss is about half the loss seen with the 2005 start date. For the 1990+9% and 1990-7% cases, the GDP losses with the early start date are about one-third of the losses with the 2005 start date (Figure 31).

- The loss in GDP, plus the funds used to purchase permits internationally, represents the total cost to the economy. With the 2005 start date, the total cost in the compliance period, 2008 to 2012, ranges from an annual average of $77 billion

Figure 30. Projected dollar losses in potential gross domestic product in the 1990+9% and 1990+9% early start cases, 1998-2020 (billion 1992 dollars)

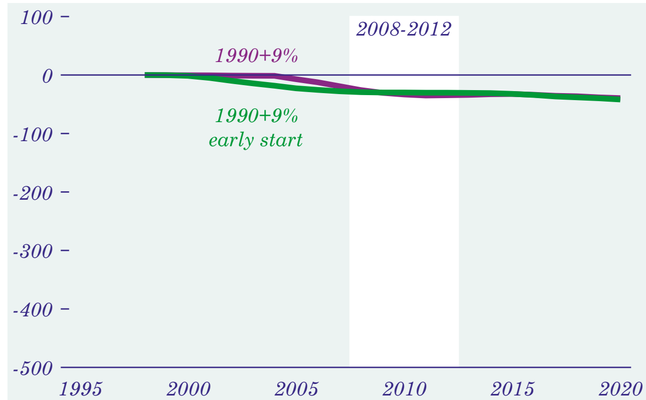
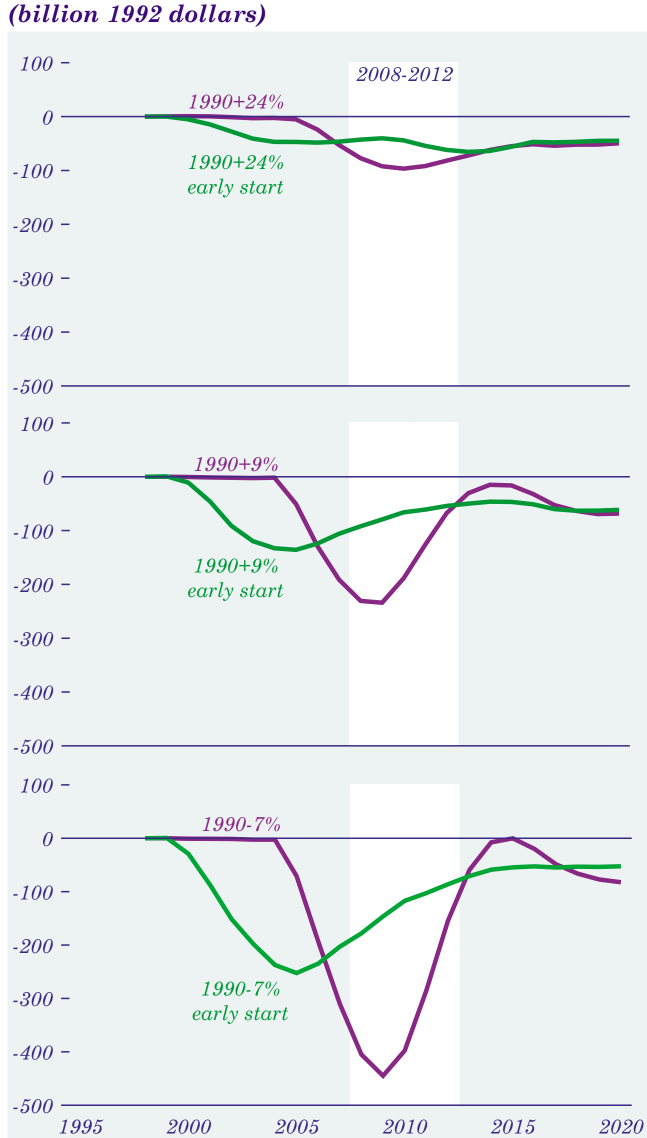


Figure 31. Projected dollar losses in actual gross domestic product in the 1990+24%, 1990+9%, and 1990-7% early start and 2005 start cases, 1998-2020 (billion 1992 dollars)



(1992 dollars) to almost four times that amount, depending on the required carbon reductions and how the revenues are recycled to the economy. This is relative to a total economy of $7 trillion in 1996, which is expected to grow to $9.5 trillion in 2010 and $11 trillion in 2020.

Proposed Ceilings on Kyoto Mechanisms

As noted above, the Kyoto Protocol includes several flexibility mechanisms; however, in Articles 6 and 17, the Protocol specifically indicates that joint implementation and Annex I trading of emissions credits "shall be supplemental to domestic actions." Supplementarity has been a topic of some debate. Those proposing limits on the flexibility mechanisms suggest that limits would lead to a more equitable method for countries to share the burden of emissions reductions; however, those opposing limits argue that the most economically efficient method for reductions is through unlimited access to the flexibility mechanisms.

On May 17, 1999, the Council of Ministers of the European Union adopted a Community Strategy on Climate Change. The Council affirmed the Buenos Aires Plan of Action as a "satisfactory result of COP4 [the fourth Conference of the Parties]," while believing "that urgent preparatory work is needed in order to implement the Buenos Aires Plan of Action by COP6 [the sixth Conference of the Parties, likely to be held late in 2000 or early in 2001].

Among other conclusions and recommendations, the Council reaffirmed "that the provisions in Articles 6, 12 and 17 of the Protocol [*52*] require that domestic action should provide the main means of meeting the commitments under Article 3 of the Protocol [*53*] and that a concrete ceiling on the use of the Kyoto mechanisms should be defined." Furthermore, the Council adopted the following proposal for limitations on trade in the commitment period:

- For purchasers, the net acquisitions for all three Kyoto mechanisms together must not exceed the higher of the two following alternatives:

  5 percent of [(base year emissions multiplied by 5) + (assigned amount over the commitment period)] / 2, or

  50 percent of the difference between the actual annual emissions in any year between 1994 and 2002 multiplied by 5 and its assigned amount over the commitment period.

- For sellers, net transfers for all three Kyoto mechanisms together must not exceed 5 percent of [(base year emissions multiplied by 5) + (assigned amount over the commitment period)] / 2.

Under the Council proposal, the limits on both acquisitions and transfers can be increased to the extent that a party achieves reductions larger than the ceiling in the commitment period through verifiable domestic actions undertaken after 1993.

The proposed limit on sellers of carbon permits is aimed at Annex I countries such as those comprising the former Soviet Union, which are likely to have lower emissions in the commitment period than in 1990 due to the economic decline of those countries in the 1990s. Compared with an unlimited trading system, restrictions on the sales of carbon permits are likely to increase the average price for the permits in an international market.

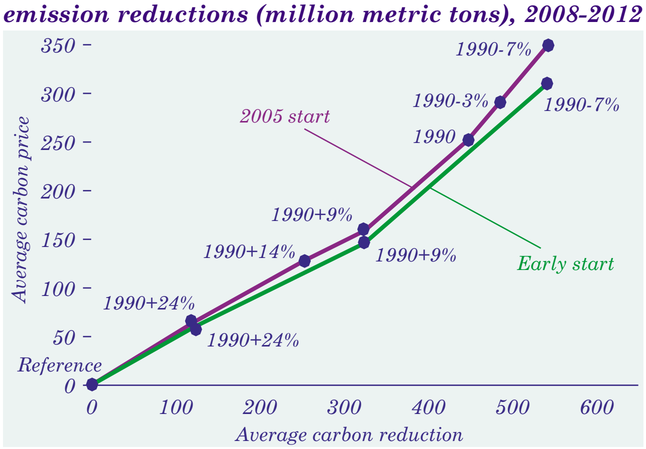
The Council proposal applies to all greenhouse gases included in the Kyoto Protocol; however, in order to consider the potential impact on the United States of the purchase limits in this proposal, only U.S. carbon emissions from energy are considered. Under the first provision: U.S. carbon emissions are 1,345 million metric tons in the base year of 1990, and its assigned amount is 7 percent below that level over 5 years, or 6,254 million metric tons. Therefore, under the first provision—5 percent of [$1,345 \times 5 + 6,254$] / 2—purchases would be limited to 324 million metric tons over the 5-year commitment period. Under the second provision, U.S. carbon emissions in the reference case of the Kyoto Protocol analysis are projected to grow to 1,600 million metric tons in 2002. Therefore, purchases would be limited to 50 percent of $1,600 \times 5 - 6,254$, or 873 million metric tons. Because the second provision results in a higher value, it establishes the U.S. limit on the use of the flexibility measures at an average annual of 175 million metric tons.

In the reference case, U.S. carbon emissions are expected to total 8,929 million metric tons in the commitment period, 2008 through 2012. Its assigned amount of carbon emissions is 6,254 million metric tons, of which 873 million metric tons can be met through the flexibility mechanisms under the Council proposal. Therefore, of average annual reductions of 535 million metric tons in the commitment period, an average of 175 million metric tons, or 33 percent, can be purchased.

Using the results of the six carbon reduction cases in the analysis of the Kyoto Protocol and the three cases in the early start analysis, the average carbon prices in the commitment period can be displayed as a function of the average carbon reductions required in that period (Figure 32). This curve represents the marginal cost of reducing energy-related carbon emissions in the United States.

Assuming that about 4 percent of the total required reduction in emissions can be met by cost-effective measures to reduce other greenhouse gases and enhance sinks, plus the ability to purchase 175 million metric tons of emissions credits abroad, a reduction in energy-related carbon emissions of 310 million metric tons is required. Using the curve for a 2005 start date, this reduction would require an average carbon price of about $150 per metric ton (1996 dollars)—about $10 per metric ton lower than the average price of $159 per metric ton in the 1990+9% case and about $85 per metric ton higher than the $65 per metric ton price in the 1990+24% case, which is the case most analogous to a full trading case in which the various flexibility measures are unlimited. With the earlier start date, the average carbon price resulting from the Council proposal would be reduced from about $150 per metric ton to about $140 per metric ton.

Figure 32. Average projected carbon prices (1996 dollars per metric ton) and annual carbon emission reductions (million metric tons), 2008-2012



The purchase of 175 million metric tons of permits, as derived from the Council proposal, is slightly higher than the level of 160 million metric tons in the 1990+9% case with the 2005 start date. As a result, the ultimate impact on the economy is moderated somewhat relative to that case. The loss in potential GDP is $31 billion (1992 dollars), compared with $32 billion in the 1990+9% case. The loss in actual GDP declines from $169 billion to $164 billion. The value of the permits purchased is $24 billion, slightly higher than the $23 billion cost in the 1990+9% case. Therefore, the total cost to the economy—the loss in actual GDP plus the purchases of international permits—totals $188 billion, compared with $192 billion in the 1990+9% case.